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ALBERTA DEPARTMENT OF ENERGY

NOVEMBER 2, 1989

90-05581/

OIL SANDS GEOLOGY FORUM
November 2, 1989
Palliser Hotel, Alberta Room
Calgary, Alberta

PROGRAM

8:30 - 9:00	Opening Remarks and Introduction
9:00 - 9:15	Overview of the Western Canada Sedimentary Basin - Daryl M. Wightman
9:15 - 9:40	Dissolution of Middle Devonian Elk Point Group Evaporites: Timing and Impact on Hydrocarbon Accumulation, Lower Cretaceous Mannville Group, northeastern Alberta - Don McPhee
9:40 - 9:50	Questions
9:50 - 10:10	Coffee
10:10 - 10:25	Data Management: South Athabasca - Desmond Wynne
10:25 - 10:50	Resource Distribution: South and Central Athabasca - Joe MacGillivray
10:50 - 11:25	Lower Mannville Sedimentology: South and Central Athabasca - Donald A.W. Keith
11:25 - 11:40	Questions
11:40 - 13:00	Lunch
13:00 - 13:25	Reservoir Geology of the Provost Upper Mannville B Pool - John Kramers
13:25 - 13:45	Petrographic Image Analysis and Pore Systems - Li-Ping Yuan
13:45 - 14:10	Effects of Shale Clasts on Reservoir Flow Properties - Stefan Bachu
14:10 - 14:20	Questions
14:20 - 14:35	Coffee
14:35 - 14:50	AOSTRA Underground Test Facility - Regional Setting - Brian Rottenfusser
14:50 - 15:05	AOSTRA Underground Test Facility - Phase A - Jane Palfreyman
15:05 - 15:15	Questions
15:15 - 15:30	Closing Remarks

CK:bw
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AGS/AOSTRA/AE OIL SANDS GEOLOGY FORUM

FOREWARD

Daryl M. Wightman

Acting Head, Oil Sands Section
Alberta Geological Survey
Alberta Research Council

The first Oil Sands Geology Forum, presented by the Alberta Geological Survey (AGS), a department of the Alberta Research Council (ARC), was held in April, 1986. Presentations covered a broad range of research that was carried out from 1979 to 1986 under a program funded jointly by the Alberta Geological Survey and the Alberta Oil Sands Technology and Research Authority (AOSTRA). In 1986, the Alberta Department of Energy (AE) became a part of the jointly funded program, and the strategic geology project, which is funded entirely by AOSTRA, was also initiated. At this second Oil Sands Forum, results from both the jointly funded (AGS/AOSTRA/AE) and Strategic (AOSTRA) research will be presented.

There are two projects within the joint program: Resource Characterization and Reservoir Analysis. The Resource Characterization project team undertakes studies of a regional nature that provide fundamental baseline data to both government and industry. These studies establish the stratigraphic framework and produce maps which delineate bitumen distribution and the associated characteristics of the resource. Depositional models are developed to interpret the three-dimensional characteristics of the reservoirs and their mineralogical attributes are also documented. This is the type of research that has traditionally been conducted by the AGS and the results comprise the morning session.

The Reservoir Analysis project is a relatively new multi-disciplinary initiative that is studying reservoirs in detail to develop new methodologies for application to enhanced oil recovery (EOR). Integration of geological studies with the petrographic image analysis of pore systems leads to a more accurate estimation of reservoir parameters. For heterogeneous portions of the reservoir, core derived values for

parameters are numerically scaled up to the reservoir grid scale by simulating fluid flow through the heterogeneous zone. The results of this research comprise the first part of the afternoon session.

Strategic Geology has been primarily involved with the AOSTRA Underground Test Facility (UTF). The project has covered a broad range of activities, from mapping the AOSTRA lease and surrounding area to delineating reservoir characteristics and developing exploitation strategies. The results of this project will be given in the latter part of the afternoon session.

The program booklet contains material for each of the presentations. We hope that attendees enjoy, and benefit from, the forum. Feedback on the forum and on specific projects is welcome as we hope to continue and enhance our interaction with both public and private sectors.

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OVERVIEW OF THE WESTERN CANADA SEDIMENTARY BASIN

DARYL WIGHTMAN

ABSTRACT

From the Late Precambrian to the Jurassic, the Western Canada Sedimentary Basin was a stable cratonic platform where a relatively thin (2 to 3 km) accumulation of marine sediments, mainly carbonate in origin, were deposited. During Jurassic times, the western margin of North America changed from passive to active as collision of superterrane I from the west caused the Columbian Orogeny. Sediment was shed from the Columbian orogen eastwards into the newly created foreland basin. The Blairmore/Mannville Groups were deposited during this orogeny as part of the westward derived sediment.

A second major tectonic event, the Laramide Orogeny, occurred during the Late Cretaceous to early Tertiary when superterrane II collided with the western edge of North America. This tectonic event involved major west to east thrusting which formed the Rocky Mountains. Large volumes of detritus were shed eastwards and maximum thicknesses of sediment were attained on the western side of the foreland basin. Due to the raised topographic relief to the west, the hydrodynamic regime changed from compaction flow to a relatively strong west to east, gravity driven groundwater flow. Also at this time, due to maximum sediment burial, organic rich source rocks in the western part of the basin were pushed through the oil generation window. Thus, because of the superimposed flow regime, the hydrocarbons that were generated migrated updip to the east. Continued sedimentation in the early Tertiary caused source rocks to become overmature in the west whereas lower rates of sedimentation to the east resulted in mature source rocks in central and immature source rocks in eastern Alberta. The entire region has been undergoing net erosion from the early Tertiary to the present.

The oil sands/heavy oil deposits represent a large portion of the hydrocarbons that were generated during the Laramide Orogeny. Therefore, bitumen in the Mannville Group probably accumulated 50 to 60 million years after the deposition of the sediment. The bitumen represents thermally mature crude oil that was biodegraded and water washed as it approached near surface, fresher water conditions. There

is a relatively smooth transition from the less viscous, more deeply buried heavy oil deposits (less biodegradation) to the more viscous, shallow oil sands deposits (more biodegradation). Biodegradation and water washing played a major role in the trapping of the near surface bitumen.

The oil sands and heavy oil deposits represent an enormous resource (approximately $275 \times 10^9 m^3$) that will undoubtedly play a key role in Alberta's future.

DISSOLUTION OF MIDDLE DEVONIAN ELK POINT GROUP EVAPORITES: TIMING AND IMPACT ON HYDROCARBON ACCUMULATION, LOWER CRETACEOUS MANNVILLE GROUP, NORTHEASTERN ALBERTA

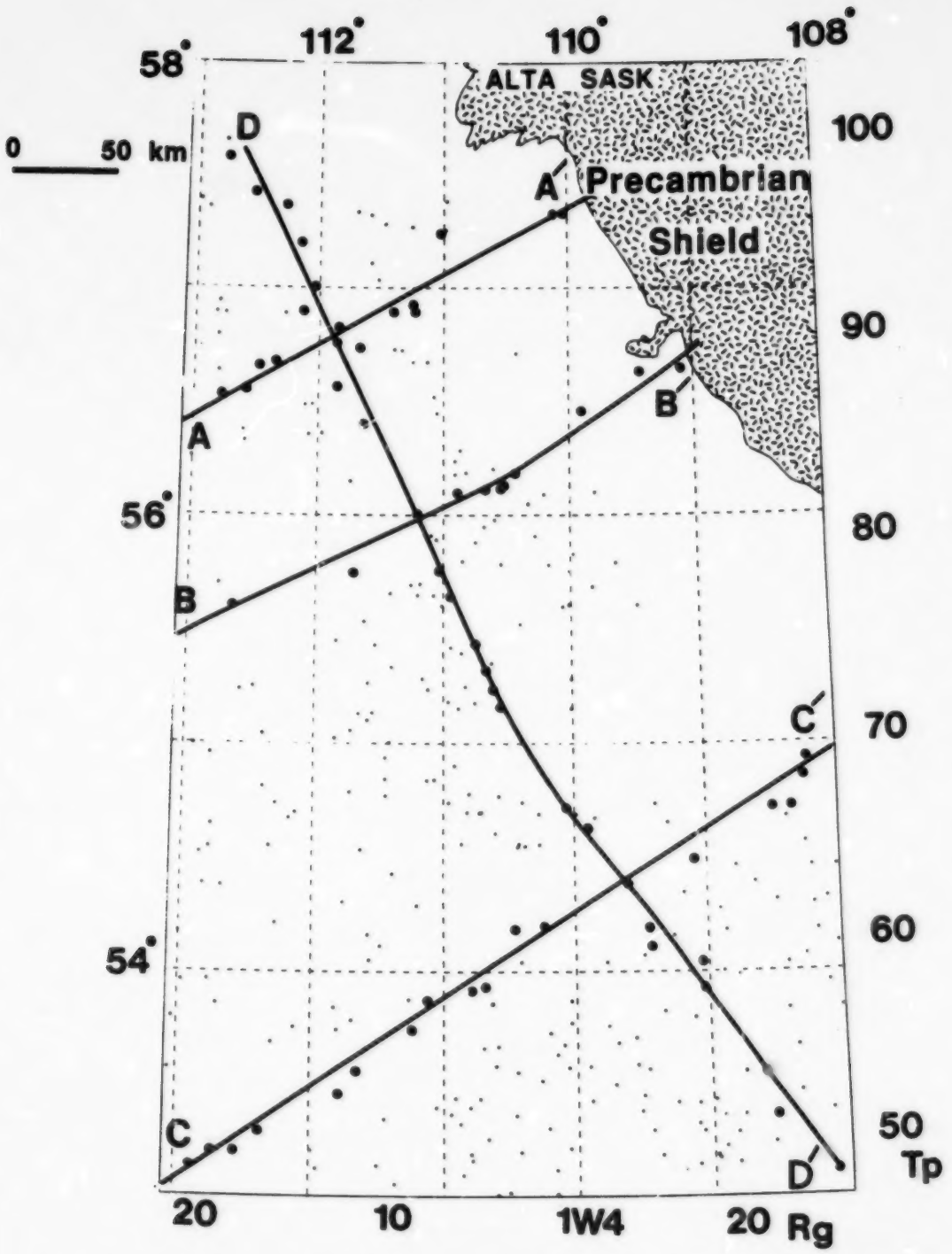
DON MCPHEE

ABSTRACT

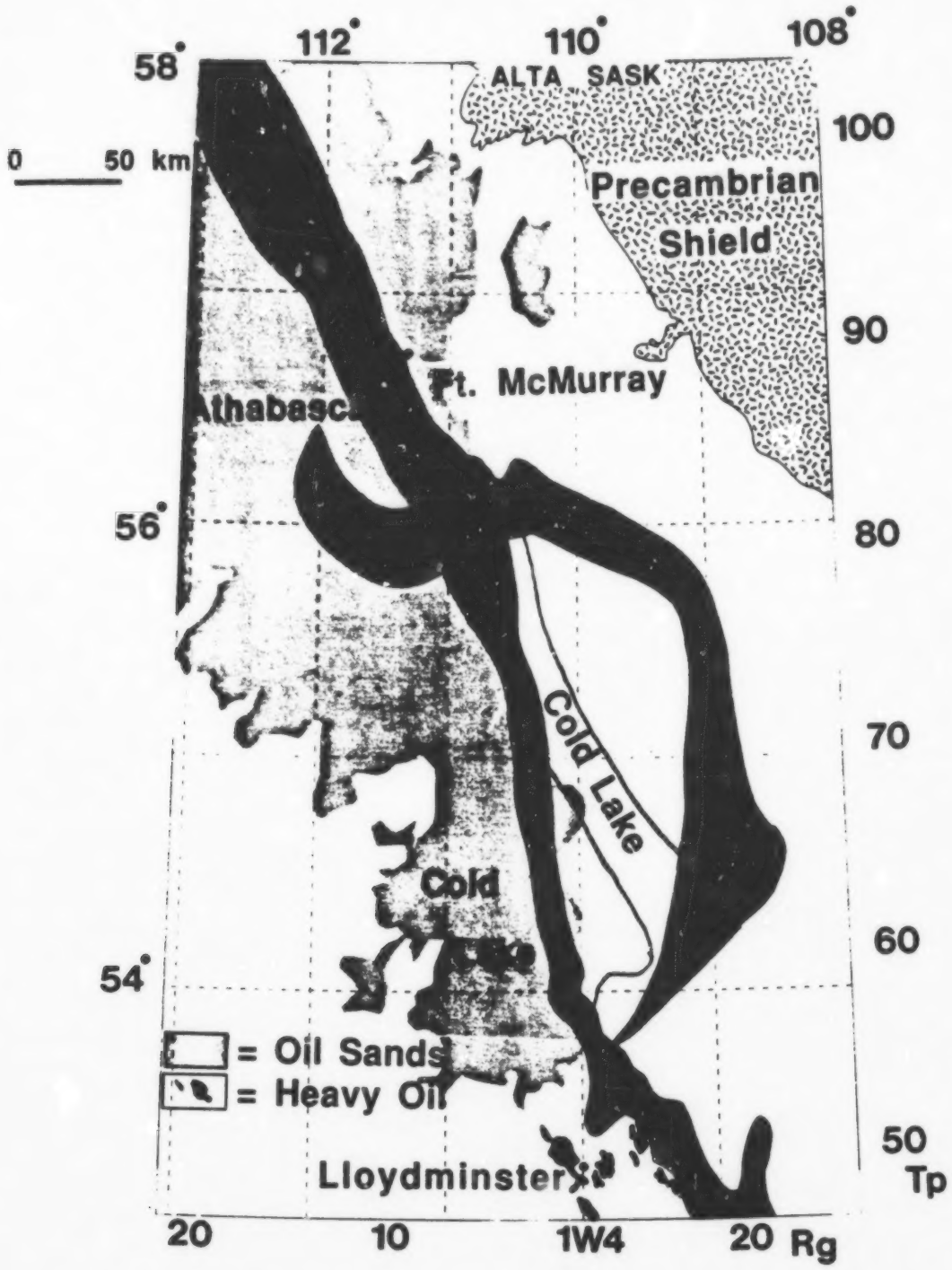
The Devonian evaporites (salts) form four mappable units within the study area: the lower and upper members of the Lotsberg Formation, the Cold Lake Formation and the Prairie Formation. They range in age from Early to Middle Devonian, are included in the Elk Point Group, and overlie rocks of Precambrian to Silurian age. The evaporites attain a maximum aggregate thickness of 425 m. All of the deposits, except the lower Lotsberg, are truncated to the northeast because of post-depositional solution of the beds. The dissolution scarp of each salt, from the youngest to the oldest, is successively offset eastwards. The Prairie salt scarp coincides approximately with the eastern limit of the Oil Sands and Heavy Oil deposits, except in the northeastern part of the Athabasca area where bitumen extends farther eastwards.

The western limit of salt dissolution in the Prairie Formation coincides approximately with a major reduction in the rate of thinning of the Upper Devonian to the northeast. If the angle of truncation was more or less constant, the zero edge of Upper Devonian strata would be located west of its present erosional edge. The preservation of Upper Devonian strata farther eastwards indicates pre-Cretaceous dissolution. This hypothetical zero edge coincides with: 1) the present northeastern limit of salt in the Prairie Formation; 2) the zone of maximum thickening in the Lower Cretaceous Mannville Group and in the post-Mannville to Second White Specks interval; and 3) the zone of maximum structural reversal of the entire sequence from the Upper Devonian to the Upper Cretaceous.

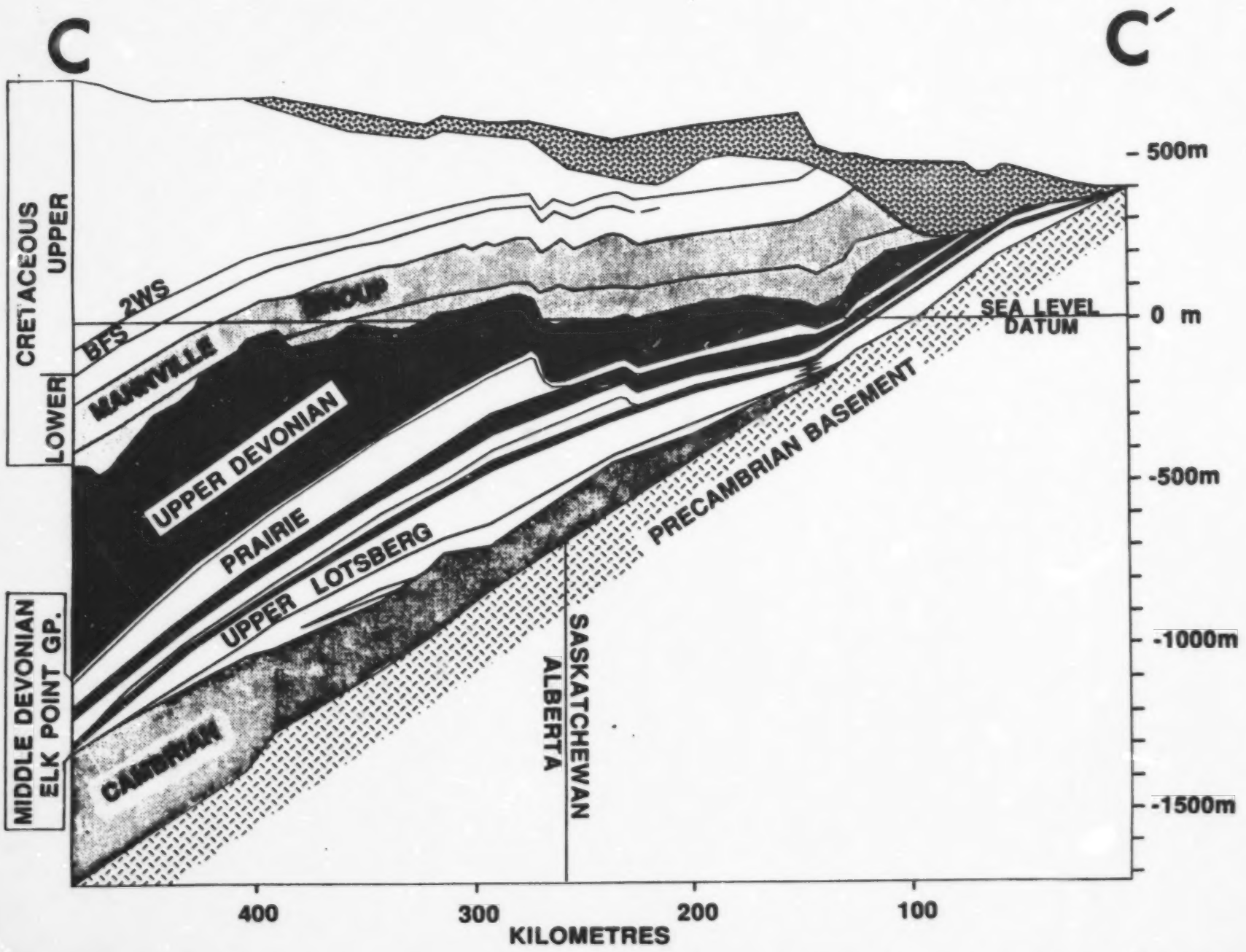
Evaporite dissolution along and just east of the Oil Sands and Heavy Oil Deposits occurred over a long time span. Forty to eighty percent of the salt was dissolved prior to the Cretaceous and up to twenty percent was dissolved during early Mannville time. Twenty to fifty percent of the dissolution occurred in the post-Mannville period and of that as much as fifteen percent took place prior to the deposition of the Second White Specks.



Study area & Cross-sections



Distribution of Hydrocarbons & Salt Scarps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BFS
GROUP
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PRAIRIE
UPPER LOTSBERG
CAMBRIAN
MIDDLE DEVONIAN
ELK POINT GP.
PRECAMBRIAN BASEMENT
SASKATCHEWAN
ALBERTA
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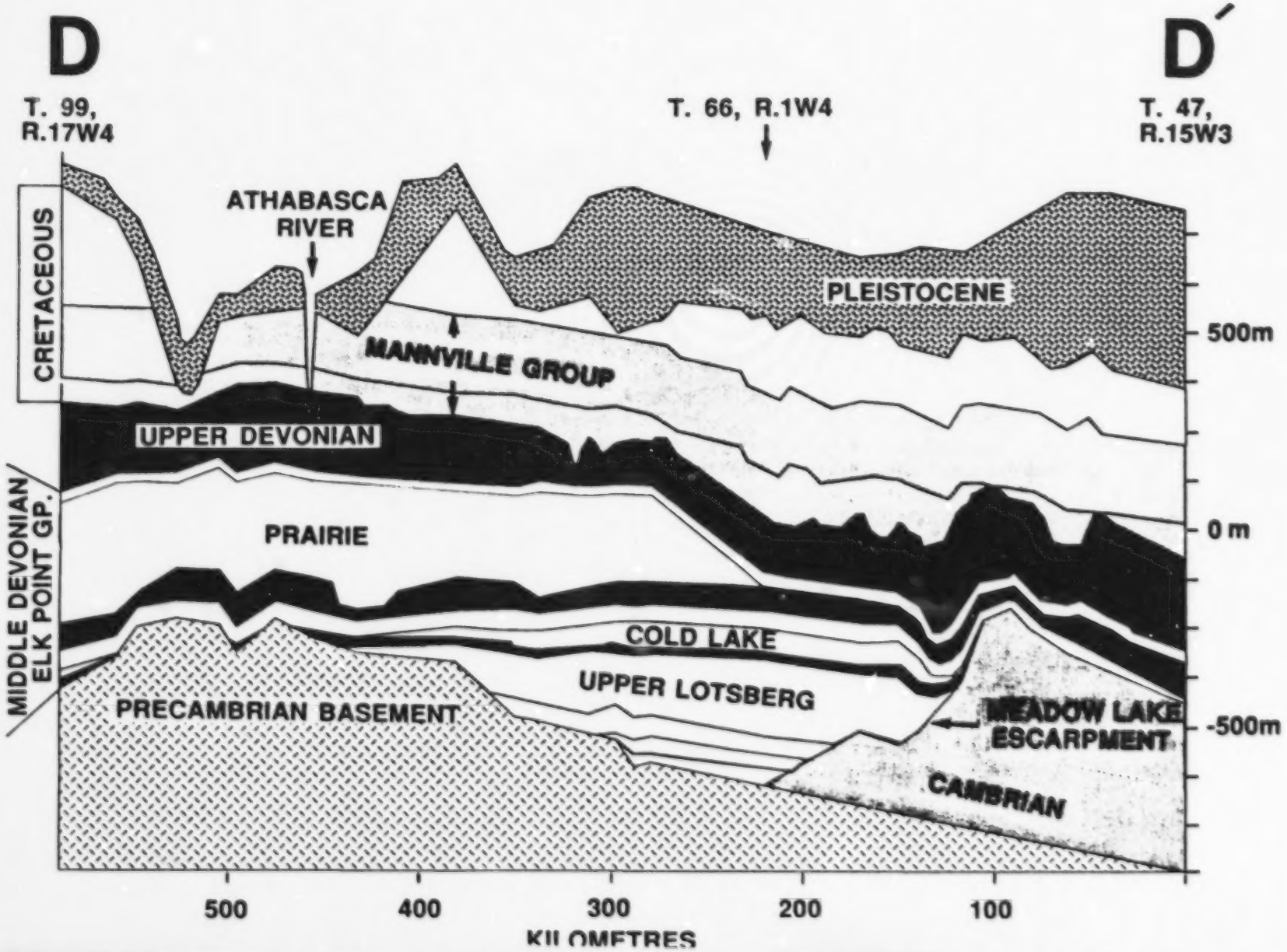
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T. 99, R.17W4
T. 66, R.1W4
T. 47, R.15W3
ATHABASCA RIVER
CRETACEOUS
MANNVILLE GROUP
PLEISTOCENE
UPPER DEVONIAN
MIDDLE DEVONIAN ELK POINT GP.
PRAIRIE
COLD LAKE
UPPER LOTSBERG
PRECAMBRIAN BASEMENT
MEADOW LAKE ESCARPMENT
CAMBRIAN
500m
0 m
-500m
500
400
300
200
100
KILOMETRES

DATA MANAGEMENT - ATHABASCA SOUTH

DESMOND WYNNE

ABSTRACT

The location and the availability of logs and core analysis data for all wells in the Athabasca South area were examined. A subset of 697 wells were selected for detailed analysis. Wells were selected on the basis of geographic distribution, the availability and quality of well logs (gamma ray, resistivity and porosity), and the presence of core analysis data. Where possible four wells per township were used for control. Picking of formation tops and marker horizons was done by visual examination of the well logs. Lithology and formation fluid data was calculated by using a computerized log analysis system.

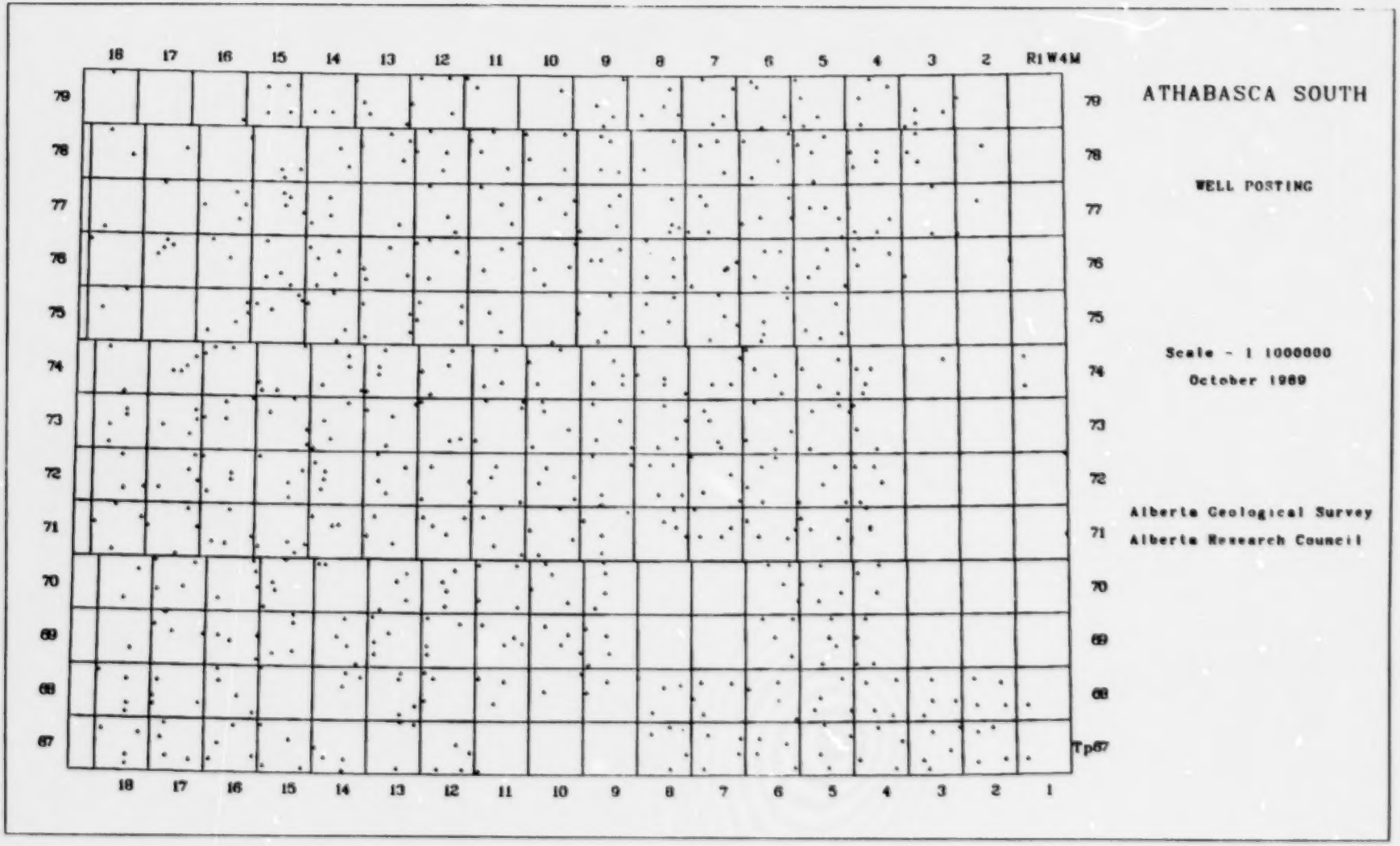
The log analysis system was calibrated by using core analysis data. Seperate constants were determined for the McMurray Formation and the Wabiskaw Member. Lithology data were derived from a volume of shale calculation based on the gamma ray log curve response. Porosity was calculated by using a complex-lithology crossplot algorithm with shale corrected density and neutron logs. Formation fluid data were calculated by using the Simmandoux water saturation equation.

A relational database was designed and built to manage the data used for mapping. Tables were created in the database for well identification and location data; for the core analysis data used to calibrate the log analysis system; for the formation and marker horizons picked from the well logs; and for all data derived from the log analysis system. All data except for the formation and marker horizons were obtained in digital form.

Standard reports using SQL (Structured Query Language) were designed to extract data for the structure and isopach (sand, bitumen, gas and water) maps. A special report using embedded SQL was designed to extract data for the bottom water maps. The appropriate formation names, marker horizon names and bitumen saturation values must be specified as parameters each time a report is used to extract data.

An automated procedure was developed to produce the maps. This procedure extracts data from the database by using one of the standard reports, contours the data, and produces the finished map. Contouring was performed by using Surface II, a contouring package developed by the Kansas State Geological Survey. The finished maps were produced by using software packages developed inhouse at the Alberta Geological Survey.

Use of the database simplified data verification and maintenance of data consistancy for all maps. Use of the automated procedure to produce the maps reduced errors, reduced the time needed to produce a map, and provided the geologist with a fast and flexible tool for analysis of the data.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ATHABASCA SOUTH
WELL POSTING
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October 1989
Alberta Geological Survey
Alberta Research Council

ABSTRACT

The Athabasca Oil Sands area is the largest deposit of hydrocarbons in Alberta with reserves of 144 billion m^3 (909 billion barrels) of bitumen. The objective of this presentation is to describe the distribution of formation fluids within the McMurray/Wabiskaw stratigraphic interval in the southern two thirds of the Athabasca Oil Sands Area (Townships 67 to 90, Ranges 1 to 18W4). Results from two projects, Athabasca Central and Athabasca South are presented.

The McMurray Formation was deposited by the infilling of a ridge and valley system developed on the sub-Cretaceous unconformity. By the end of McMurray Formation time the valley system had been filled and the transgression of the boreal sea led to the deposition of the Clearwater Formation sands and shales. The Wabiskaw Member is the lowermost unit of the Clearwater Formation and was deposited directly on the underlying McMurray Formation.

The McMurray Formation sands are unconsolidated, relatively clean, quartz sands. The best McMurray Formation reservoirs are developed within two valley systems where thick channel sands occur. The thickest McMurray Formation bitumen sands in the study area (exceeding 65 m of greater than 3 weight percent bitumen) are in the northern part of the eastern valley system. Water sands occur within the valley system (up to 85 m) along the eastern edge of the study area. The remainder of the valley systems generally exceed 20 m (greater than 3 weight percent bitumen) of bitumen sands.

Bottom water is a development concern and has an impact on recovery strategy. McMurray Formation bottom water sands occur in lows on the sub-Cretaceous unconformity. These bottom water sands tend to be localized (on the order of magnitude of a township in size), usually less than 15 m thick, and are scattered throughout the valley system.

An abrupt bitumen/water contact trends north/south through the eastern valley system. No bitumen occurs east of the contact. The McMurray

Formation bitumen migrated updip and was confined stratigraphically by the overlying Clearwater shales. Final trapping of the bitumen appears to have occured when it was biodegraded to the point of immobility.

The Wabiskaw Member consists of unconsolidated, muddy sands and shales. Two Wabiskaw Member reservoirs occur in the study area; one in the northwest region of the central Athabasca area (over 10 m of greater than 3 weight percent bitumen sands) and the other in the east-central region of the Athabasca South area (over 35 m of greater than 3 weight percent bitumen sands).

The thick Wabiskaw reservoir of Athabasca South dips to the southwest, with bitumen saturated sands grading to water sands down dip, and gas sands (underlain by water sands) updip. Bitumen migration appears to have been directly from the underlying McMurray Formation as it can be inferred from well logs that the two units are in direct communication. Structure and facies play a role in the bitumen trapping, but from the examination of cross sections bitumen biodegradation still appears to be important.

The major contrasts between the distribution of resources in the McMurray Formation and the Wabiskaw Member are related to the composition and geometry of their sands. The McMurray Formation bitumen sands are thicker, cleaner sands than the Wabiskaw Member but lack their lateral continuity. Both reservoirs have active pilots and both reservoirs provide future opportunities.

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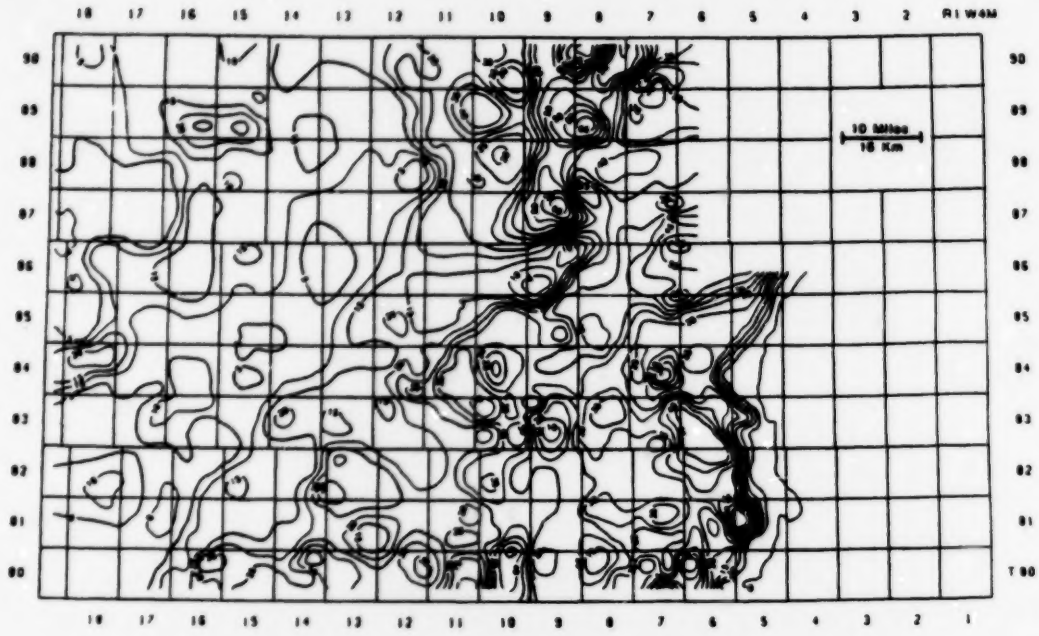


Figure 1. Isopach map of McMurray Formation sands with greater than 3 weight percent bitumen, Athabasca Central.

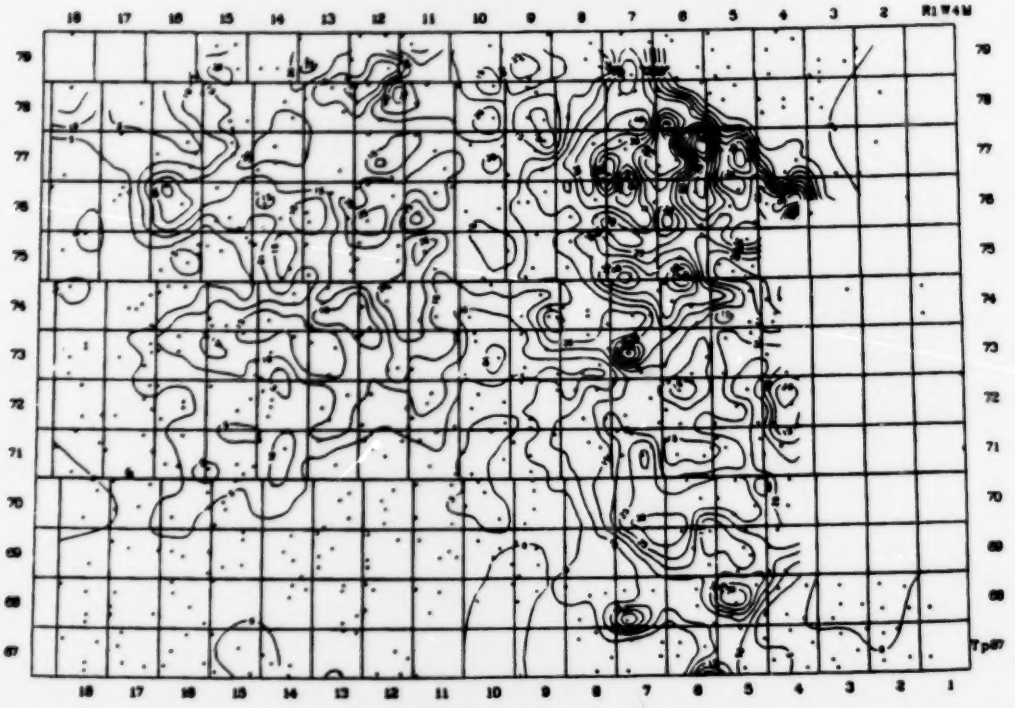


Figure 2. Isopach map of McMurray Formation sands with greater than 3 weight percent bitumen, Athabasca South.

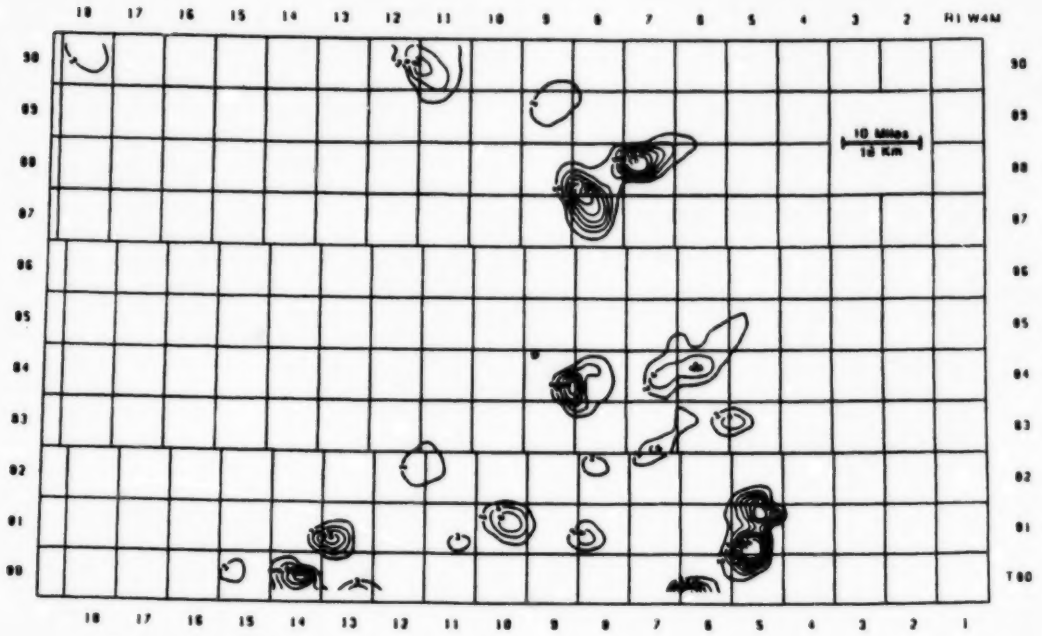


Figure 3. Isopach map of McMurray Formation bottom water sands, Athabasca Central.

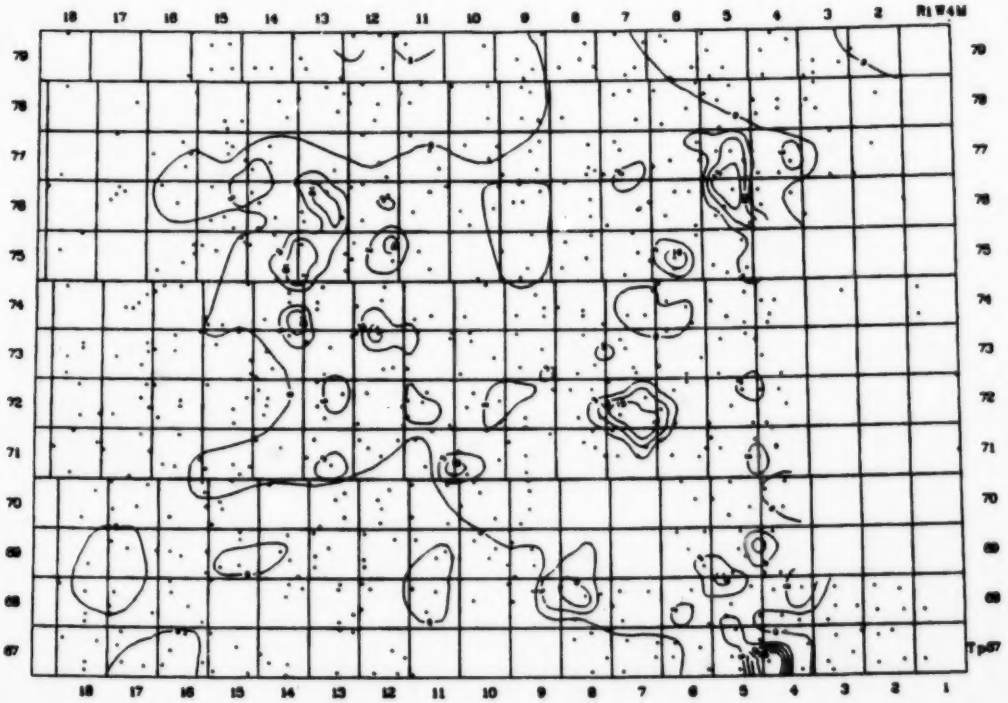


Figure 4. Isopach map of McMurray Formation bottom water sands, Athabasca South.

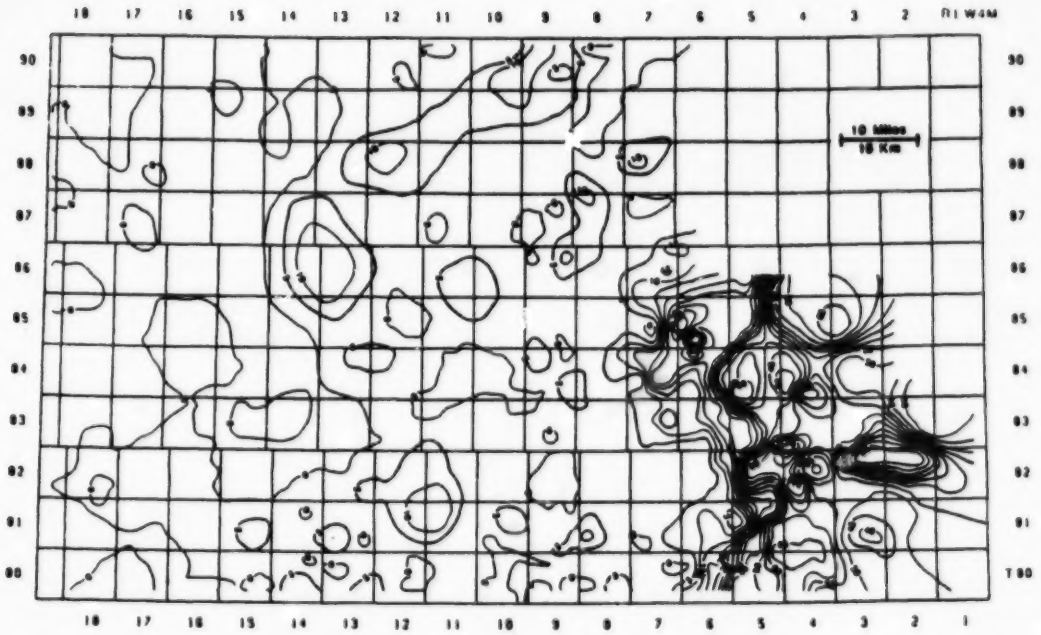


Figure 5. Isopach map of McMurray Formation water sands, Athabasca Central.

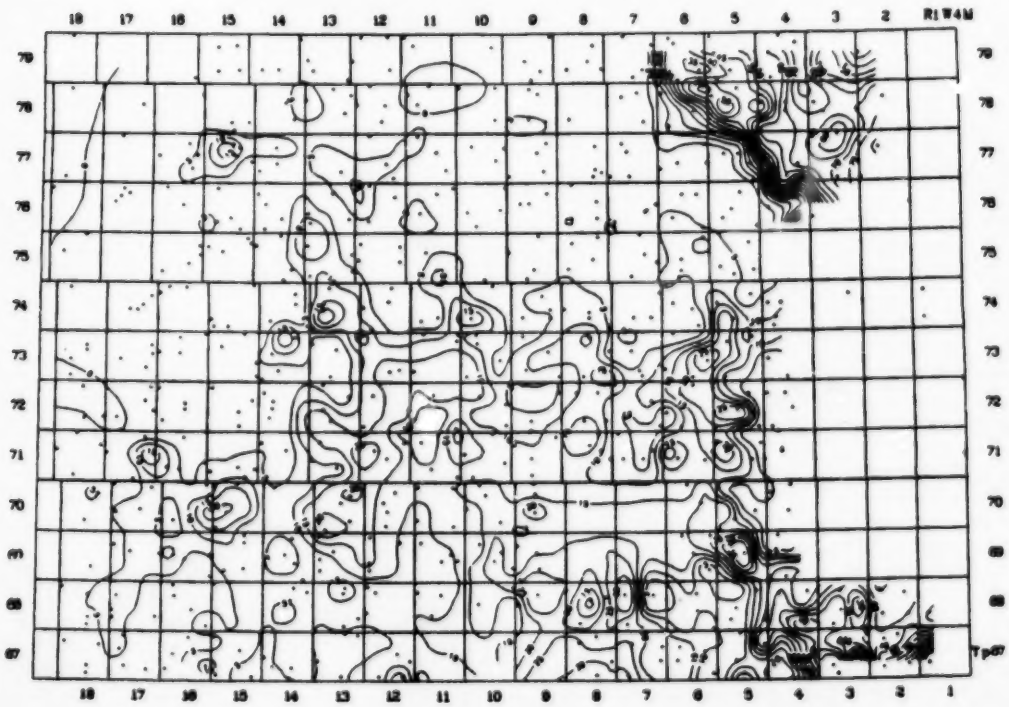


Figure 6. Isopach map of McMurray Formation water sands, Athabasca South.

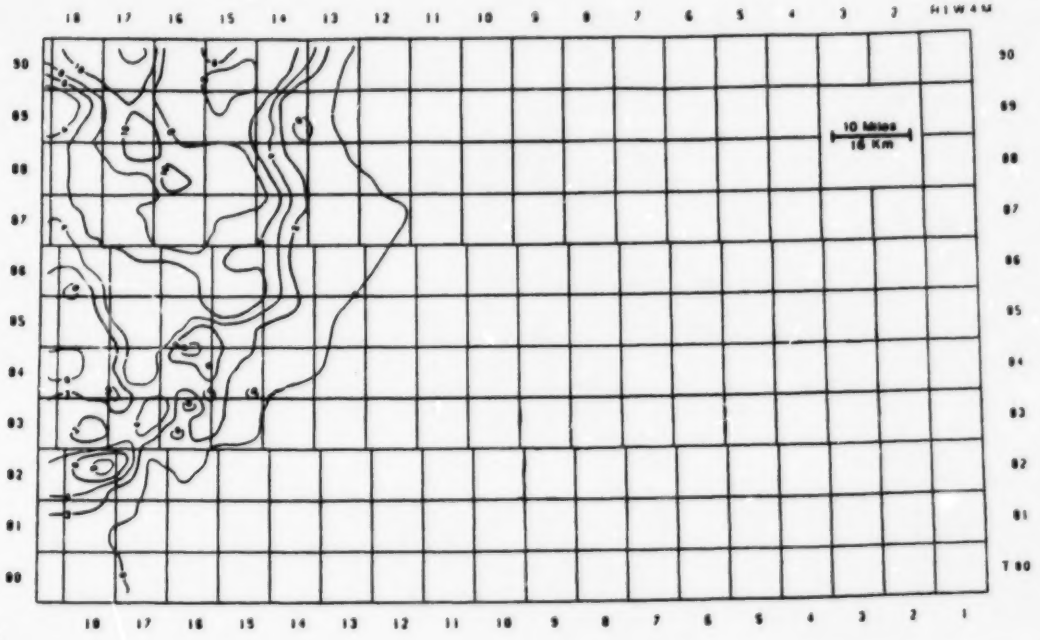


Figure 7. Isopach map of Wabiskaw Member sands with greater than 3 weight percent bitumen, Athabasca Central.

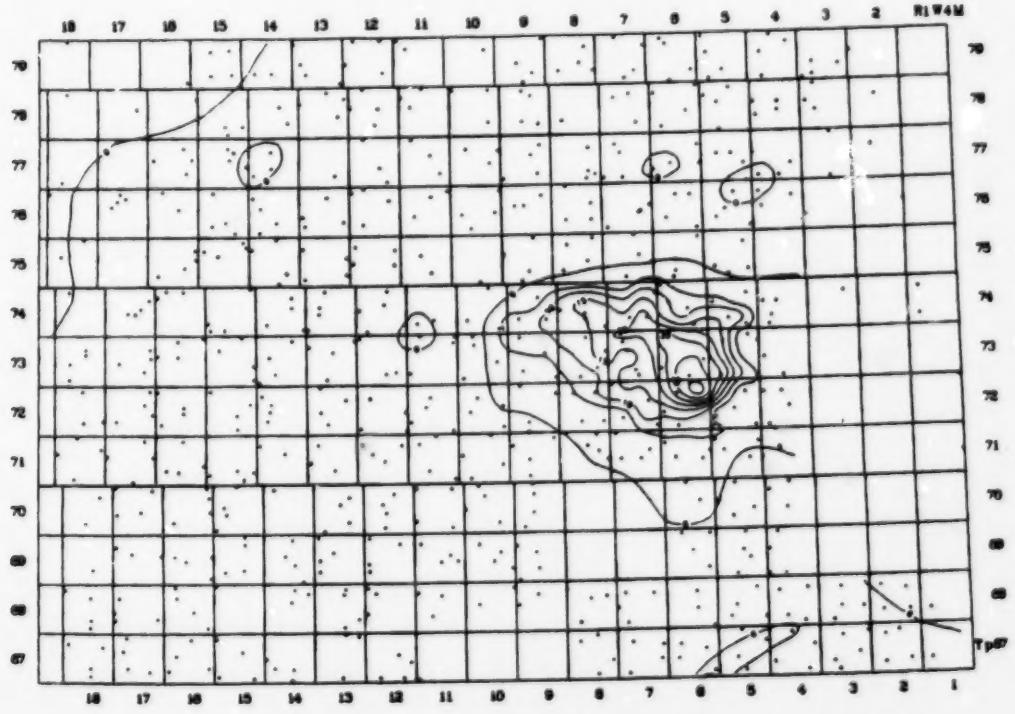


Figure 8. Isopach map of Wabiskaw Member sands with greater than 3 weight percent bitumen, Athabasca South.

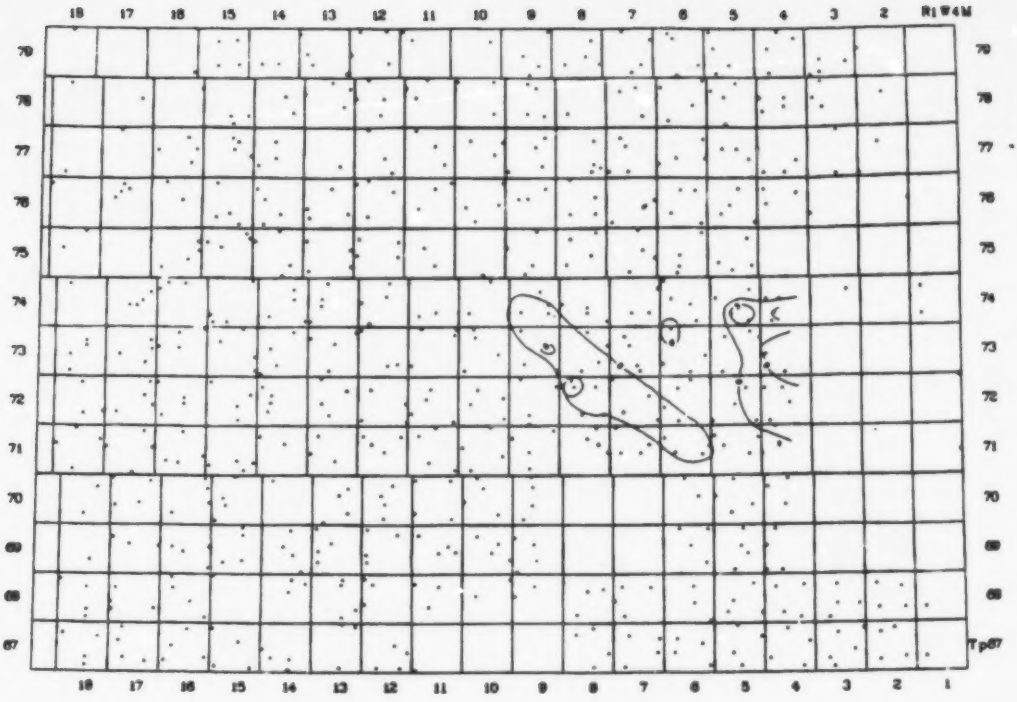


Figure 9. Isopach map of Wabiskaw Member bottom water sands, Athabasca South.

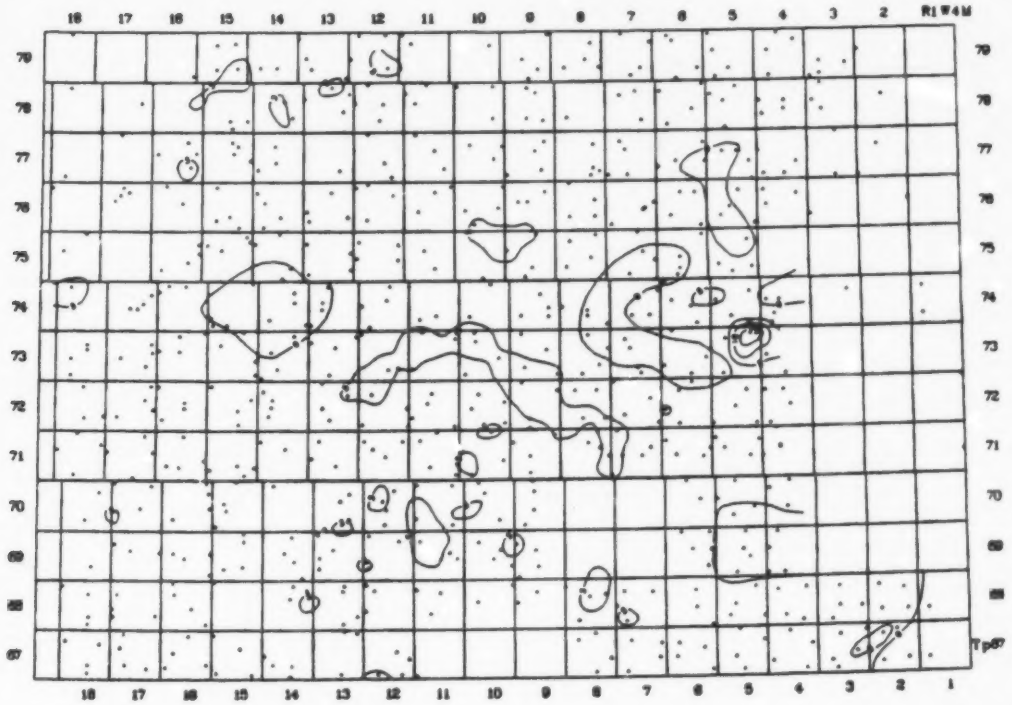


Figure 10. Isopach map of Wabiskaw Member water sands, Athabasca South.

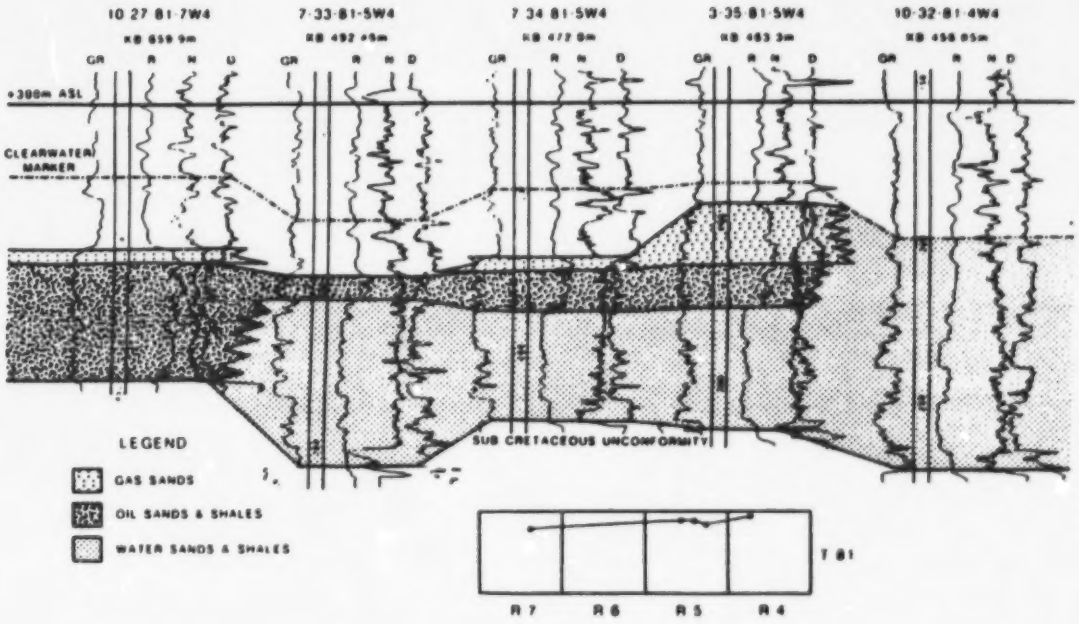


Figure 11. Structural cross section through the bitumen/water contact in Athabasca Central.

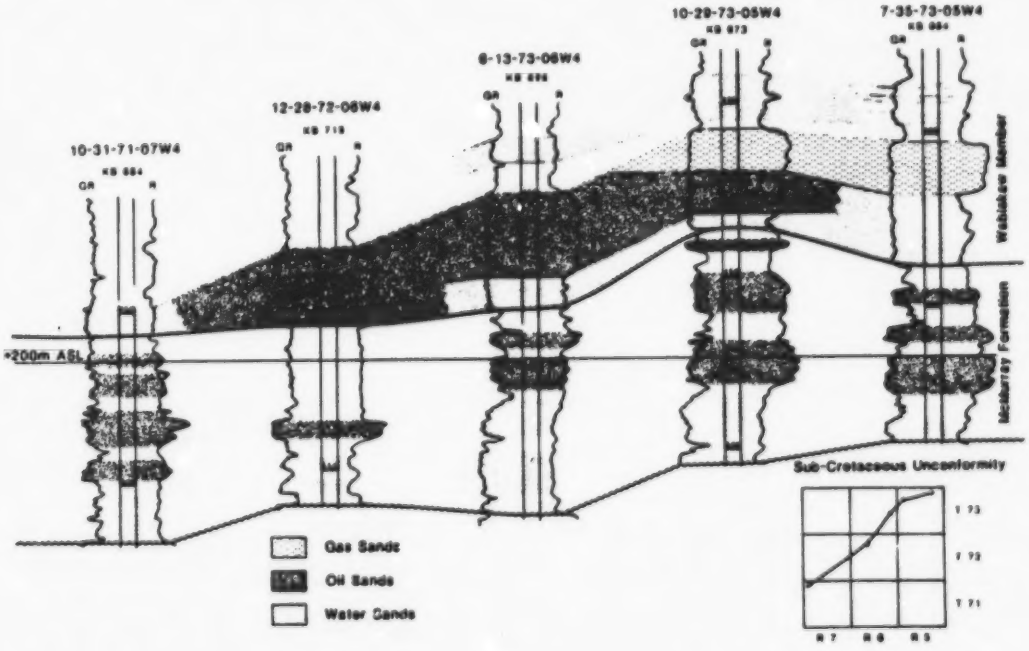


Figure 12. Structural cross section through the Wabiskaw Member reservoir in Athabasca South.

LOWER MANNVILLE SEDIMENTOLOGY - ATHABASCA SOUTH AND CENTRAL

D.A.W. KEITH, D.M. WIGHTMAN, H. BERHANE,
J.R. MACGILLIVRAY, D. WYNNE AND T. BEREZNIUK

ABSTRACT

Regional sedimentology study of the Lower Mannville Group (McMurray Formation and overlying Wabiskaw Member of the Clearwater Formation) in the Central (Townships 80-90, Ranges 1-18W4) and Southern (Townships 67-79, Ranges 1-18W4) Athabasca Oil Sands Area reveals a diverse and complex array of sedimentation styles and resulting reservoir geometries. Over 1000 well logs and 100 cores were examined for this study along with information from palynological and mineralogical samples.

The relatively mature sands (quartz arenites to sublitharenites and subarkoses), siltstones and mudstones of the McMurray Formation were laid down in generally northerly trending valleys developed on underlying Devonian carbonates. McMurray deposition occurred during the southward advance and later inundation by the Boreal sea. A main McMurray Valley is situated in the eastern part of the study area, where the effects of dissolution of underlying salts are pronounced. Numerous smaller tributary valleys join the main McMurray valley system. The underlying relief creating the ridge and valley topography, along with southward transgression of the Boreal sea are the primary controls on McMurray sedimentation.

Recognition of distinct sedimentation styles allows for informal division of the McMurray Formation into the McMurray B (lower and middle McMurray) and overlying McMurray C (upper McMurray). The sandy facies of the McMurray B (for Blocky sands) show blocky, upward-fining sequences. Palynological and ichnological indicators within the McMurray B show an upward increase in paleosalinities from continental to marginal marine environments. These deposits are interpreted as fluvial channel systems progressing upward to fluvial-estuary channel systems. Indications of tidal influence on sedimentation, such as rhythmic variations in thickness of mudstone and sand laminations, are present, particularly in the upper McMurray B. The reservoir facies of the McMurray B are: high angle cross stratified sands, current ripple cross stratified sands, and interbedded current ripple cross laminated

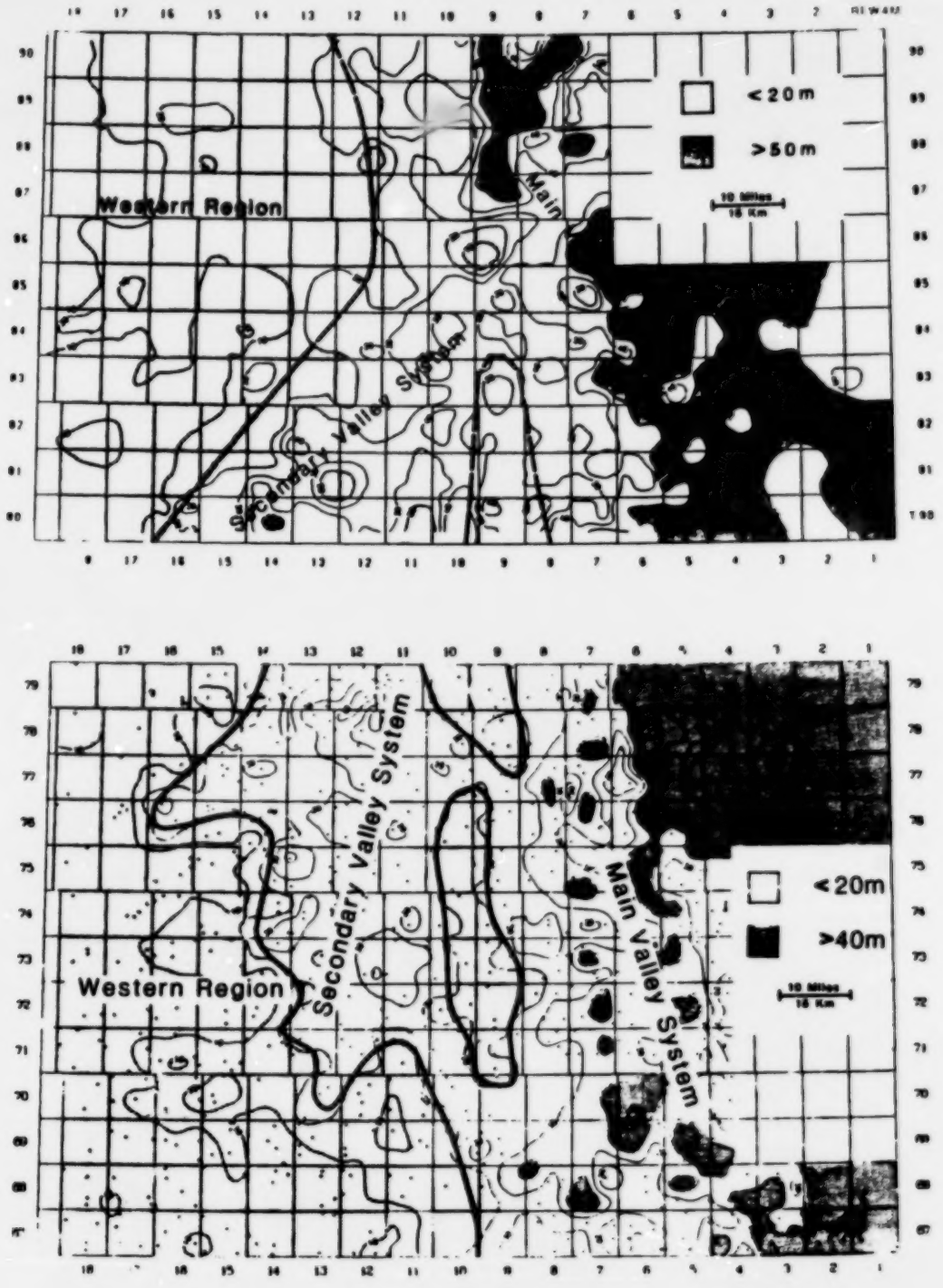
sands and bioturbated mudstones. Reservoirs of the McMurray B are relative narrow (tens of m), sinuous, and potentially very thick fluvial and estuarine channel sands. Variable amounts of intercalated mudstone laminations, beds and clasts are potential permeability barriers.

In contrast to the McMurray B, the upper portion of the McMurray Formation typically shows 1 m to 5 m upward-coarsening well log signatures which show good lateral continuity (up to tens of km). This portion of the McMurray is informally referred to as the McMurray C, for Coarsening-upward well log signatures. The paleosalinities of the McMurray C are higher than the McMurray B but ichnology, palynology and sedimentary structures such as syneresis cracks suggest abrupt fluctuations. McMurray C deposits are interpreted as lower shoreface shoaling sequences within lacustrine, estuary mouth to brackish bay settings. The reservoir facies of the McMurray C are: interbedded wave ripple cross laminated sands and mudstones, and thickly bedded wave ripple cross laminated and hummocky cross stratified sands. McMurray C reservoirs are generally thinner but more laterally extensive than McMurray B sands.

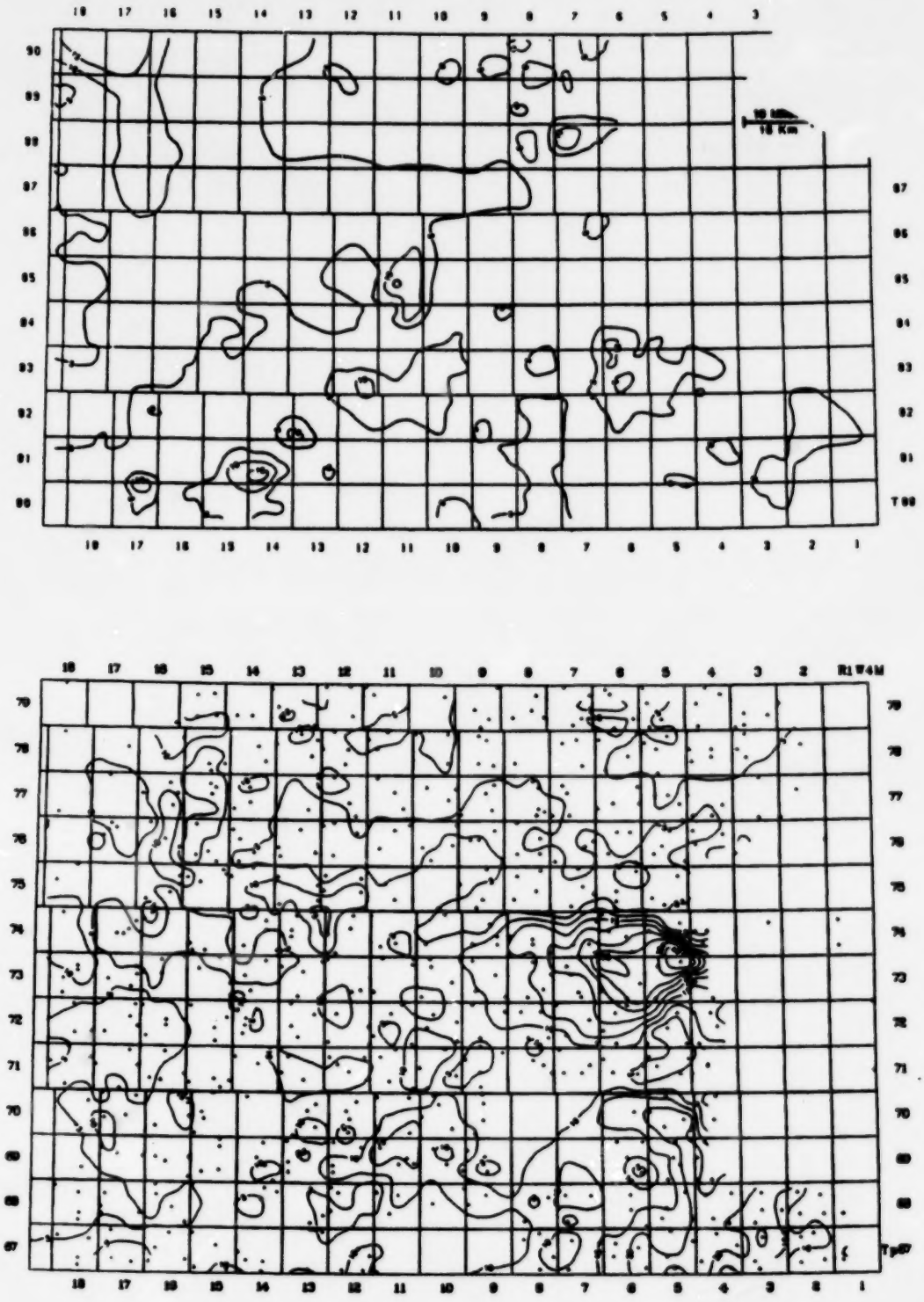
A ravinement surface with significant, although local, erosion (over 20 m) on the top of the McMurray Formation has been recognized in the southern region of the study area. This erosion may be the result of fluvial incisement during a relative sea level low stand prior to the region's inundation by the Boreal sea. An interval with high glauconite concentrations, locally showing a transgressive ichnology suite, overlies this ravinement surface.

The Wabiskaw Member is predominately a muddy unit with significant sandy accumulations occurring in the southeastern and northwestern regions of the study area. Semi-mature litharenite to feldspathic litharenitic sands, silts and shale of the Wabiskaw Member have been divided into a number of facies. The most important reservoir facies is horizontal to low angle inclined glauconitic sands. This facies fills many of the scours on the top of the McMurray Formation, where they are interpreted as lower delta front to lower shoreface sands. Elsewhere in the study

area the Wabiskaw was deposited as lower shoreface coarsening-upward successions on a broad shelf (although not necessarily fully marine). Potential permeability barriers of calcite cemented zones are common in the sands of the Wabiskaw Member. These relatively thick (to a few tens of m), laterally continuous sands are less stable than the McMurray sands but offer more laterally extensive reservoirs.

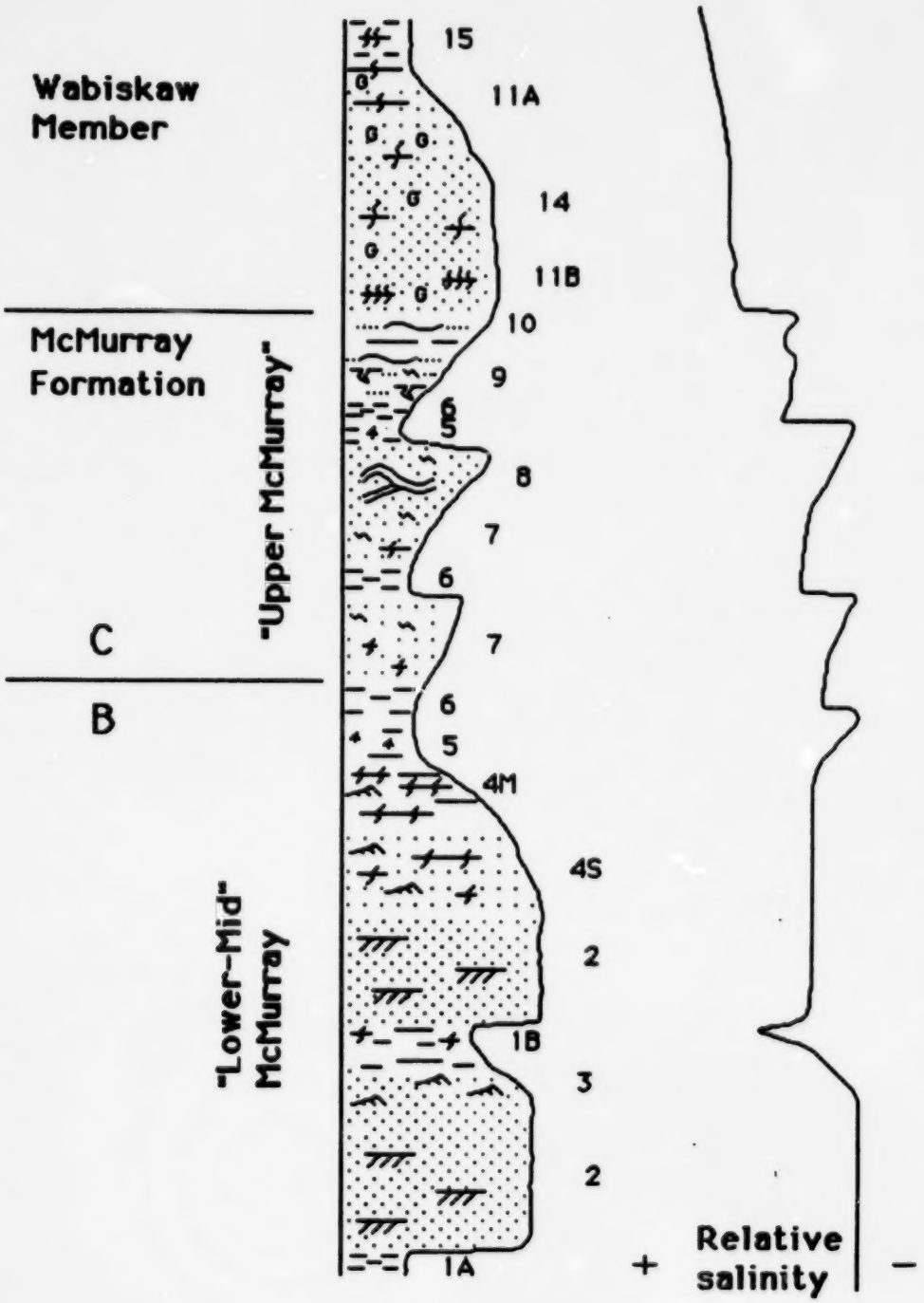


McMurray Formation sands isopach of Athabasca Central and South study areas. A 10 m contour interval is used in both maps with the relatively thick and thin sand isopach regions indicated. The locations of McMurray Formation valley systems with thick sand isopachs and western region with thin sand isopachs are also indicated.



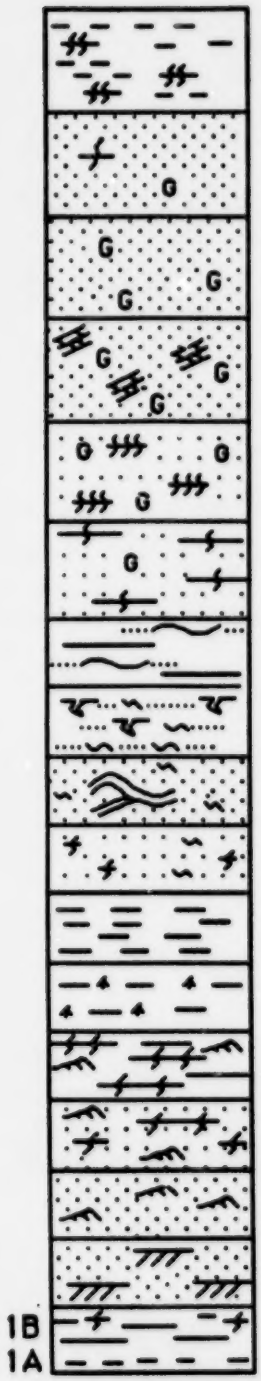
Wabiskaw Member of the Clearwater Formation sands isopach of Athabasca Central and South study areas. A 10 m contour interval is used in both maps.

Facies Composite



Composite litholog of McMurray Formation and Wabiskaw Member of the Clearwater Formation facies in the Athabasca South region. Not drawn to scale. Relative grain size patterns are indicated by the right-hand profile of the litholog (coarser to right, finer to left). Relative paleosalinities are indicated on the right side of the figure. Brief facies descriptions are provided on the following figure.

Facies



15 Dark grey silty marine mdst

14 Horiz -low angle incl sst

13 Poorly sorted glauconitic sst

12 Current RXL glauconitic sst

11B Intbd sst and mdst

11A Extremely biot intbd glauconitic sst and mdst

10 Dark gray carb mdst with wave RXL sst

9 Syneresis cracked mdst with wave RXL sst

8 Thickly bedded wave RXL and HCS sst

7 Intbd wave RXL sst and mdst

6 Dark gray -black mdst (Flood Mud)

5 Light gray rooted mdst (Paleosols)

4M Biot intbd mdst and sst (Muddy Lat Acc)

4S Biot intbd sst and mdst (Sandy Lat Acc)

3 Current RXL to small trough X-stratified sst

2 High angle trough X-stratified sst

1B Dark (Brackish) mdst

1 1A Dark (Continental) mdst

Facies divisions and brief descriptions from a regional core study of the McMurray Formation and Wabiskaw Member of the Clearwater Formation in the Athabasca South region.

RESERVOIR GEOLOGY OF THE PROVOST UPPER MANNVILE B POOL, EAST-CENTRAL ALBERTA

J.W. KRAMERS

ABSTRACT

The Provost Upper Mannville B Pool, in the heavy oil belt of east central Alberta, is contained in McLaren Formation sands of Upper Mannville (Lower Cretaceous, Albian) age. The reservoir is up to 35m thick and contains local areas of bottom water, a water to oil transition zone and patches of overlying gas. Original oil in place has been estimated at 34,200,000 m^3 of 13° API oil. Wells in the reservoir have some primary production.

The reservoir sediments were deposited in fluvial environments filling a McLaren valley that was aggraded during a relative rise in sea level. The valley cut into and through earlier, regional, shallow marine McLaren Formation coarsening upward cycles. The valley fill sediments were deposited in a sandy, low sinuosity fluvial system, similar to that found in the sandy braided river deposits of the South Saskatchewan River in central Saskatchewan. The valley fill sediments can be divided into a number of lithofacies representing different depositional environments. The reservoir sands are contained within three of these: the blocky channel, shale clast, and channel margin lithofacies. Reservoir sands are mineralogically mature and dominantly litharenites. Diagenesis is limited and consists predominantly of clay mineral diagenesis.

The blocky channel lithofacies forms the main portion of the reservoir and consists of trough and planar, cross bedded, well sorted sands. Grain size varies from medium grained at the base to fine- to medium grained near the top. Core derived permeabilities are in the 4 to 5 Darcy range for k_h; k_v ranges from 1/2 to 2/3 of k_h. Porosity values are approximately 30%. The blocky channel lithofacies is up to 20-25 m thick and was deposited in the main part of the channel complex.

The shale clast lithofacies occurs within the blocky channel lithofacies and could be considered a subfacies. It consists of shale, silty shale or carbonaceous siltstone clasts in a matrix of fine- to medium grained heavy oil sands. The clasts vary in size from <1 cm to dm's. Shape varies from equant to flat with a mean length over width ratio of approximately 2. Density of the shale clasts varies from an occasional clast to as much as

85% in some parts of the core. Gross thickness of this heterogeneous lithofacies is up to 14m, with the thickest continuous interval being 3m. Lateral continuity of shale clast zones is expected to be in the order of 10s to 100s of metres. In one of the pilots, a shale clast zone can be correlated between wells in an east to west direction, a distance of 400m, whereas in the north to south direction this same zone can only be correlated between two wells 25m apart. The shale clast lithofacies was deposited locally in the main part of the channel complex with the clasts coming predominantly from erosion of the channel cutbank.

The channel margin lithofacies is found overlying and transitional with the blocky channel lithofacies. It represents a fining upward from the sandy blocky channel lithofacies to the shaly abandonment lithofacies. Grain size varies from fine- and very fine grained at the base to silty argillaceous sand with interbedded shale and silty beds. Permeability, porosity and oil saturation also decrease towards the top. Sedimentary structures vary from cross bedding at the base to laminations, ripple laminations, and climbing ripples near the top. Thickness of this lithofacies ranges from 1m to 5m. Deposition occurred in the margins of the channel complex, on the edge and on top of point bars.

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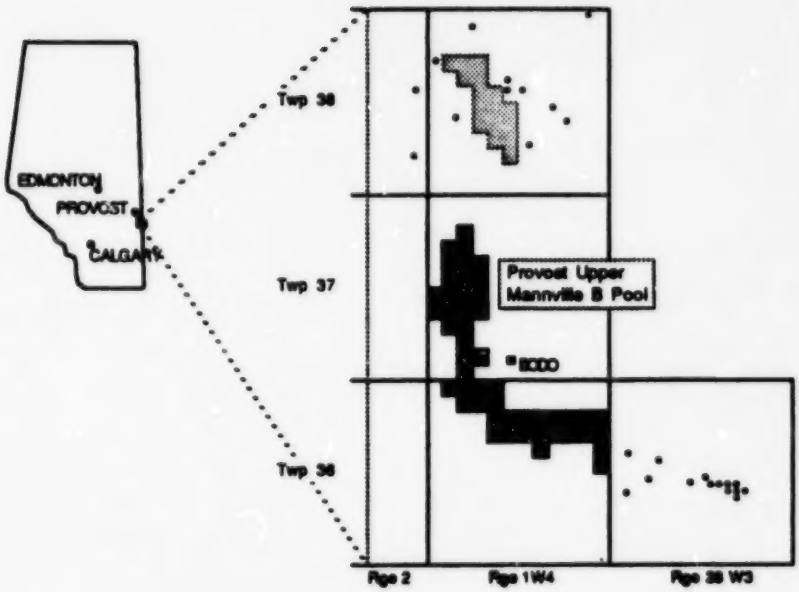

Figure 1. Map showing the location of the Provost Upper Mannville B Pool.

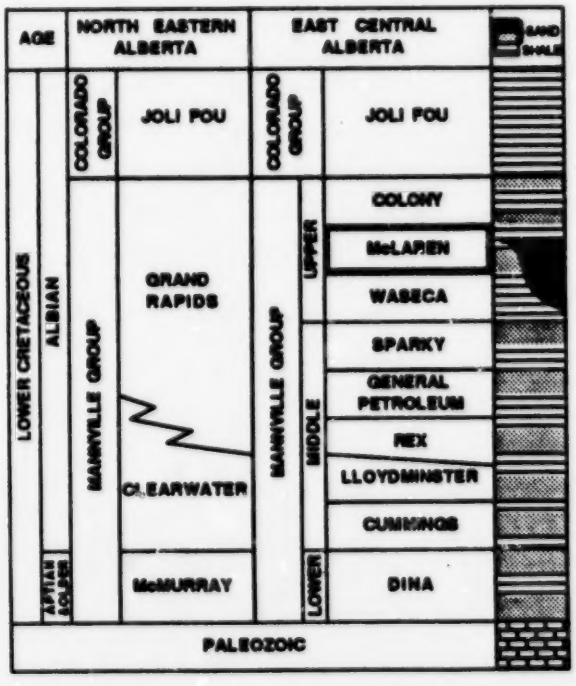

Figure 2. Lower Cretaceous stratigraphy in east central Alberta.

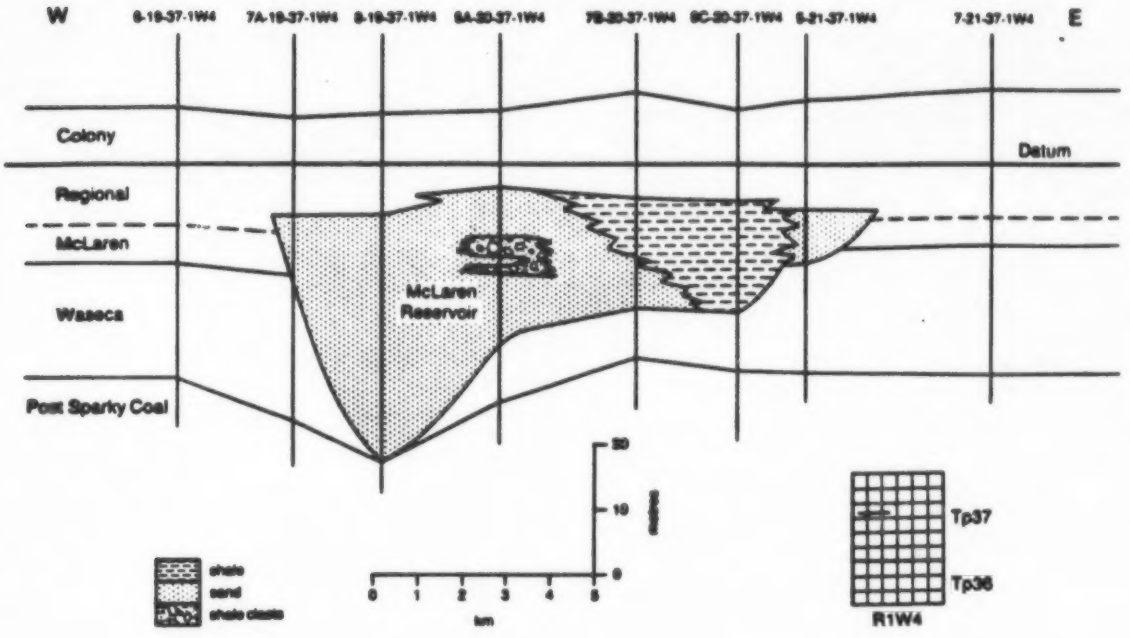

Figure 3. West to east stratigraphic cross section through the Provost Upper Mannville B Pool.

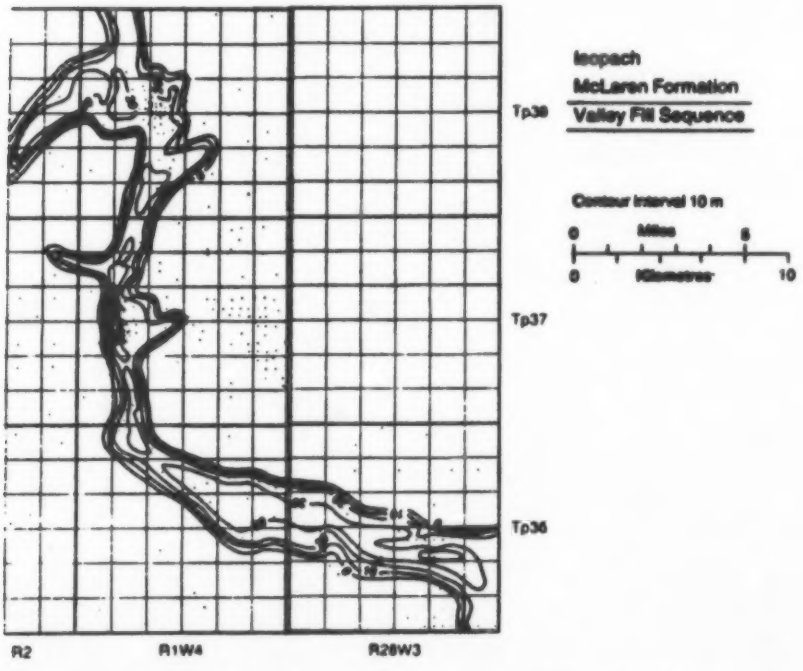

Figure 4. Isopach of the McLaren Formation valley fill sequence.

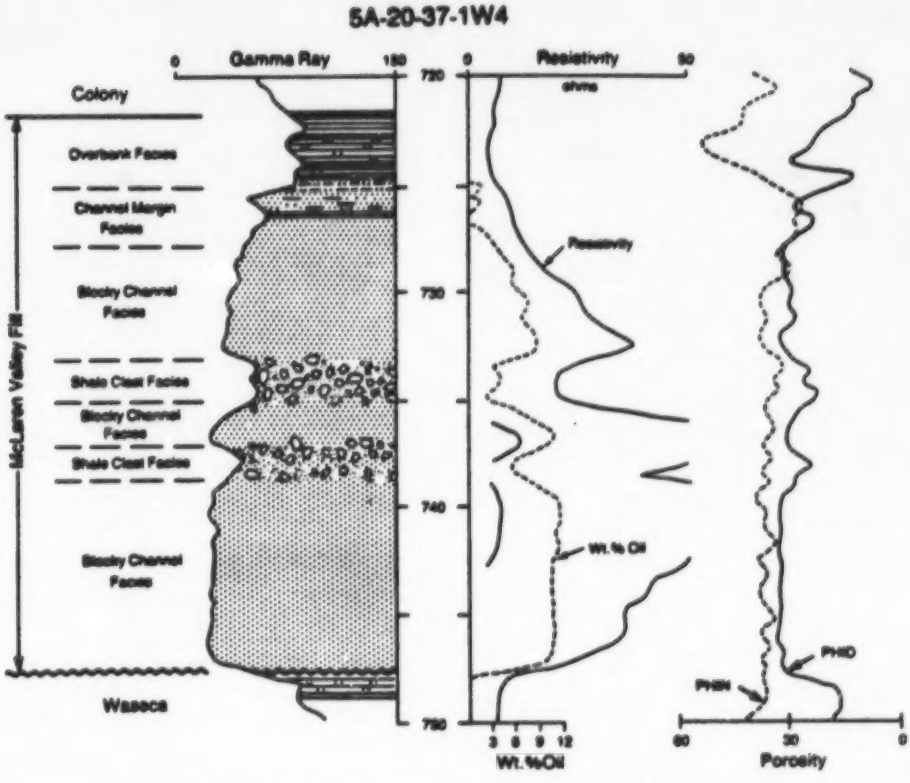

Figure 5. Typical well log from the Provost Upper Mannville B Pool showing four of the five lithofacies found in the reservoir.

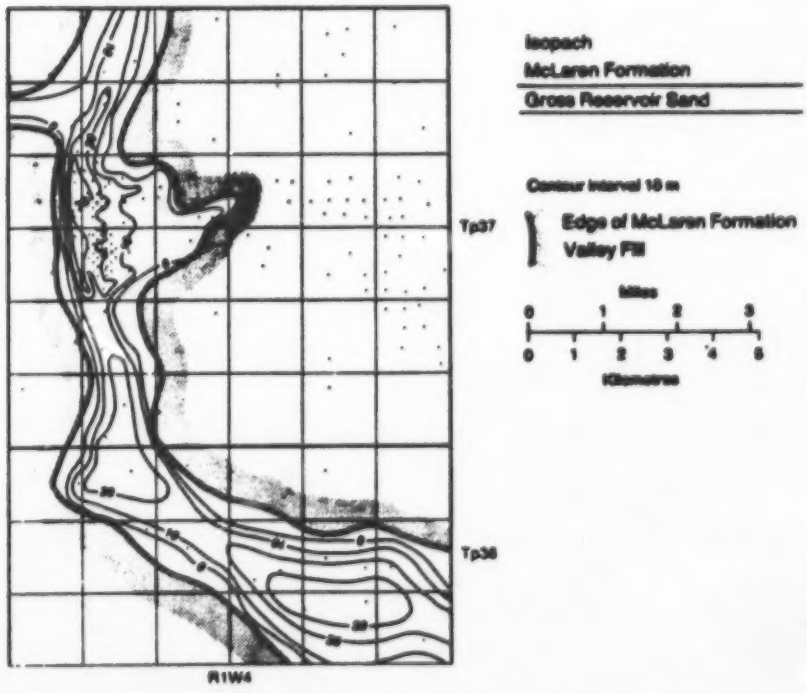

Figure 6. Isopach of the gross thickness of reservoir sands.

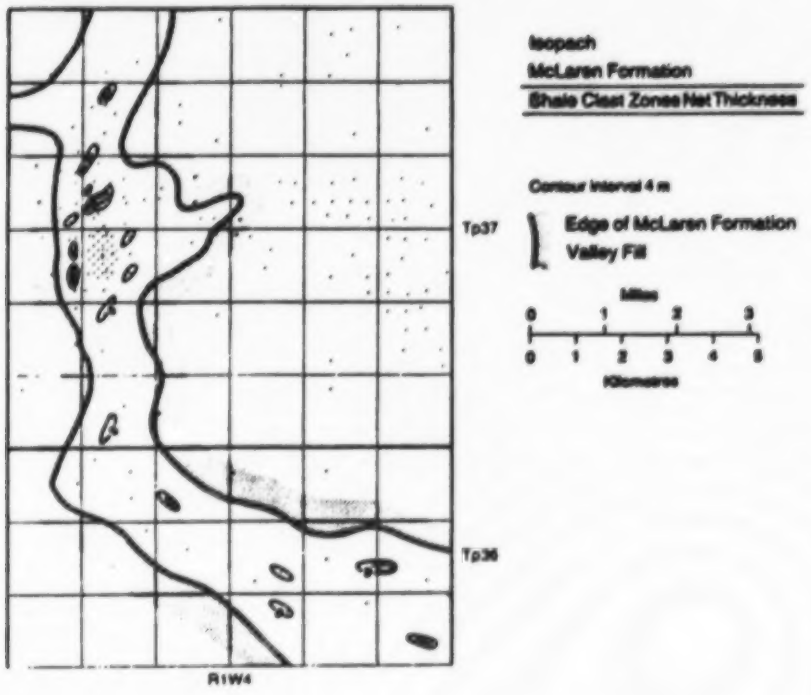

Figure 7. Isopach of the gross thickness of shale clast zones.

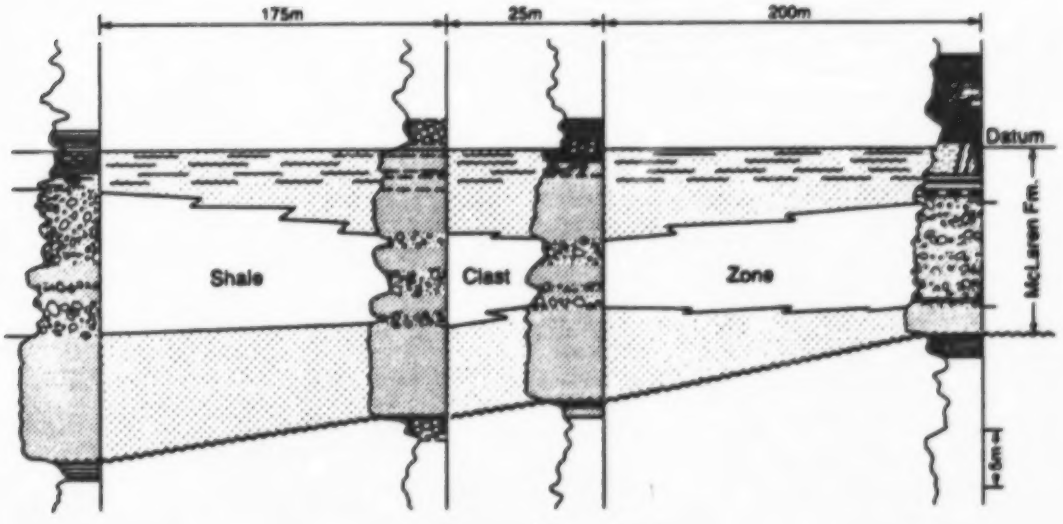

Figure 8. Correlation of shale clast zones between closely spaced wells in an EOR pilot.

PETROGRAPHIC IMAGE ANALYSIS AND PORE SYSTEMS

LI-PING YUAN

ABSTRACT

Petrographic image analysis has been used to analyze the pore systems of the Provost Upper Mannville B Pool. The relationship between pore types and lithofacies has been established. Permeabilities were found to be highly correlated to pore sizes and connectivities measured from thin sections.

Special image analysis algorithms have been improved or developed to measure pore size and connectivity from two dimensional pore images. A pore size distribution has been derived from an erosion-dilation algorithm which is especially suitable for highly irregular geometry, such as pore images. This algorithm has been improved by a factor of forty to eighty on the CPU time. The pore size distribution is further divided into a smooth component and a rough component. A connectivity measurement is then defined as the ratio of the rough component to the total pore area. This measurement varies between zero and one, which indicate the least and the best connectivities respectively.

The pore sizes and connectivities measured from vertical thin sections were found to be strongly correlated to horizontal permeability (R^2= 0.88). This strong correlation provides a new method for estimating permeability and confirms that three dimensional pore geometry information does exist on two dimensional images and can be effectively measured. On the other hand, the image data measured from horizontal thin sections are less, but still significantly, correlated to horizontal permeabilities (R^2= 0.72). This is a result of horizontal laminae, which can be better sampled by a vertical thin section. The horizontal thin section may cut through only one or a few of the many laminae in a plug, whereas the vertical thin section cuts through all the laminae.

Four end-member pore types were derived and corresponded well to four lithofacies. The oil-saturated blocky channel facies has a significant amount of large and highly connected pores which result in the highest permeability among the four lithofacies. The water-saturated blocky

channel facies has a medium to large, but less connected, pore network with medium permeability. The transitional facies between blocky channel and channel margin is characterized by an extra amount of medium sized and highly connected pores which provide a medium to high permeability for this facies. Finally, a small and less connected pore network is closely associated with the channel margin facies and with the lowest permeability. These pore types can also be used to infer other petrophysical properties, such as the capillary pressure, residual oil saturation, and foam flow properties, for each lithofacies. Therefore, this geological lithofacies information can be effectively used for the reservoir characterization.

PUBLICATIONS

Kramers, J.K., Bachu, S., Cuthiell, D.L., Prentice, M.E. and Yuan, L.P., 1989, A multidisciplinary approach to reservoir characterization: the Provost Upper Mannville B Pool: Journal of Petroleum Technology, v. 28, p. 48-58.

Yuan, L., Image Analysis of Pore Size Distribution and Its Application, Proceedings of the Colloquium on "Statistical Applications in the Earth Sciences" November 14-18, 1988, Ottawa, Ontario, in press.

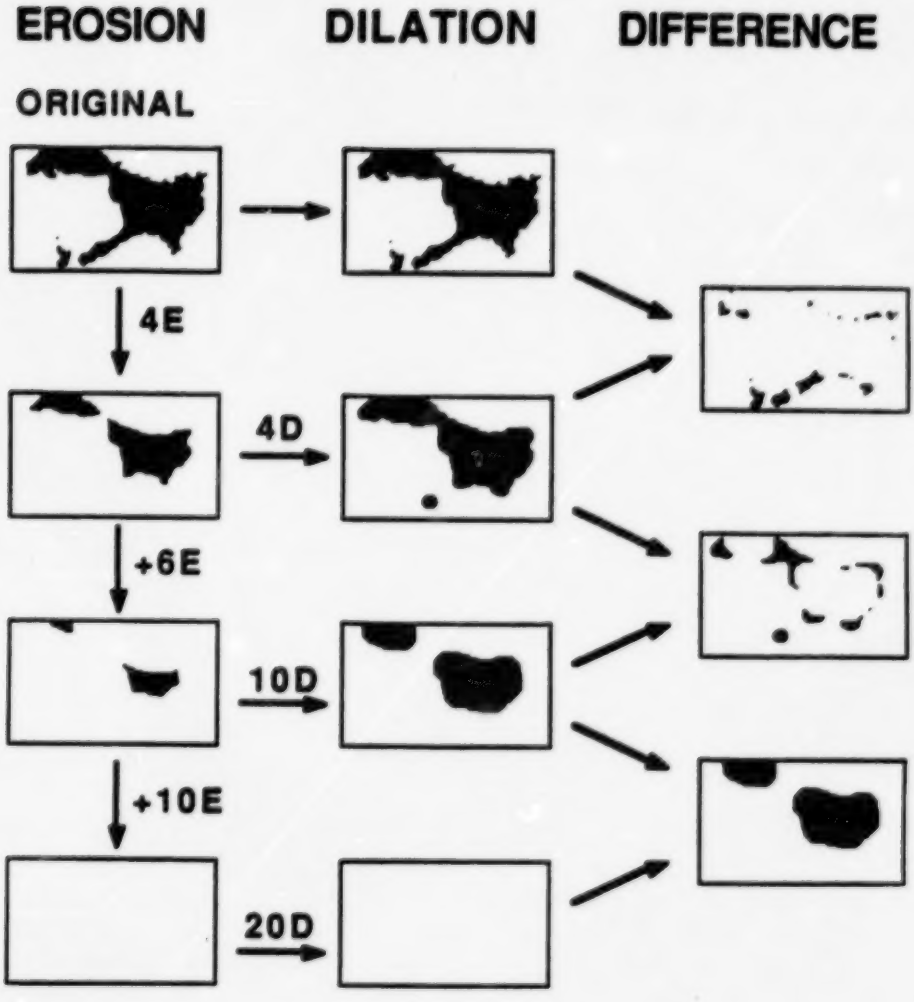

Figure 1. Erosion-dilation image processing algorithm. Dilated images represent a sequential loss of porosity from small features to large features. This is used as a size distribution by measuring the differences between subsequent dilated images.

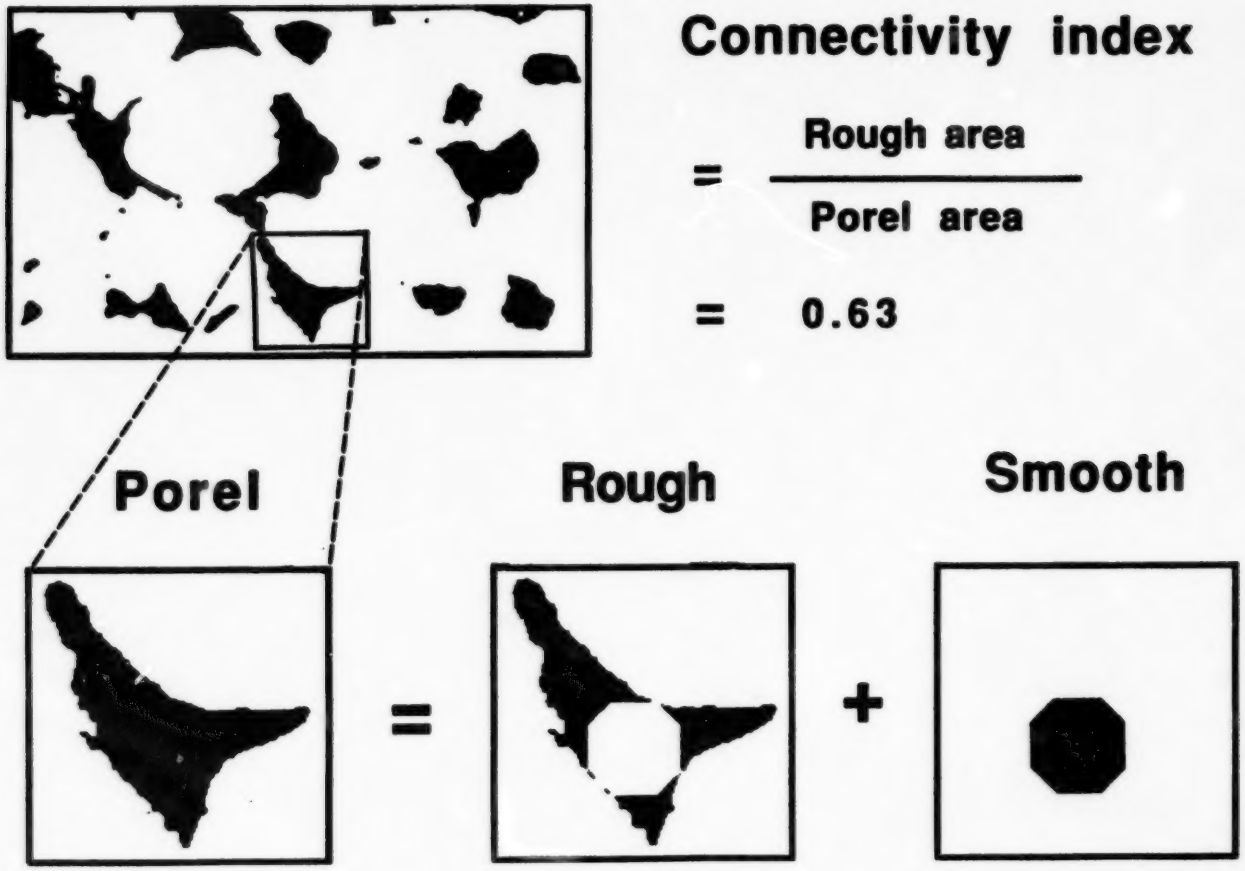

Figure 2. A porel (pore element) is a discrete unconnected patch of porosity. The smooth component is the portion with the largest size which resembles an inscribed circle of the porel. The rest of the porel is rough component. The ratio of the rough component to the porel area is defined as a connectivity index.

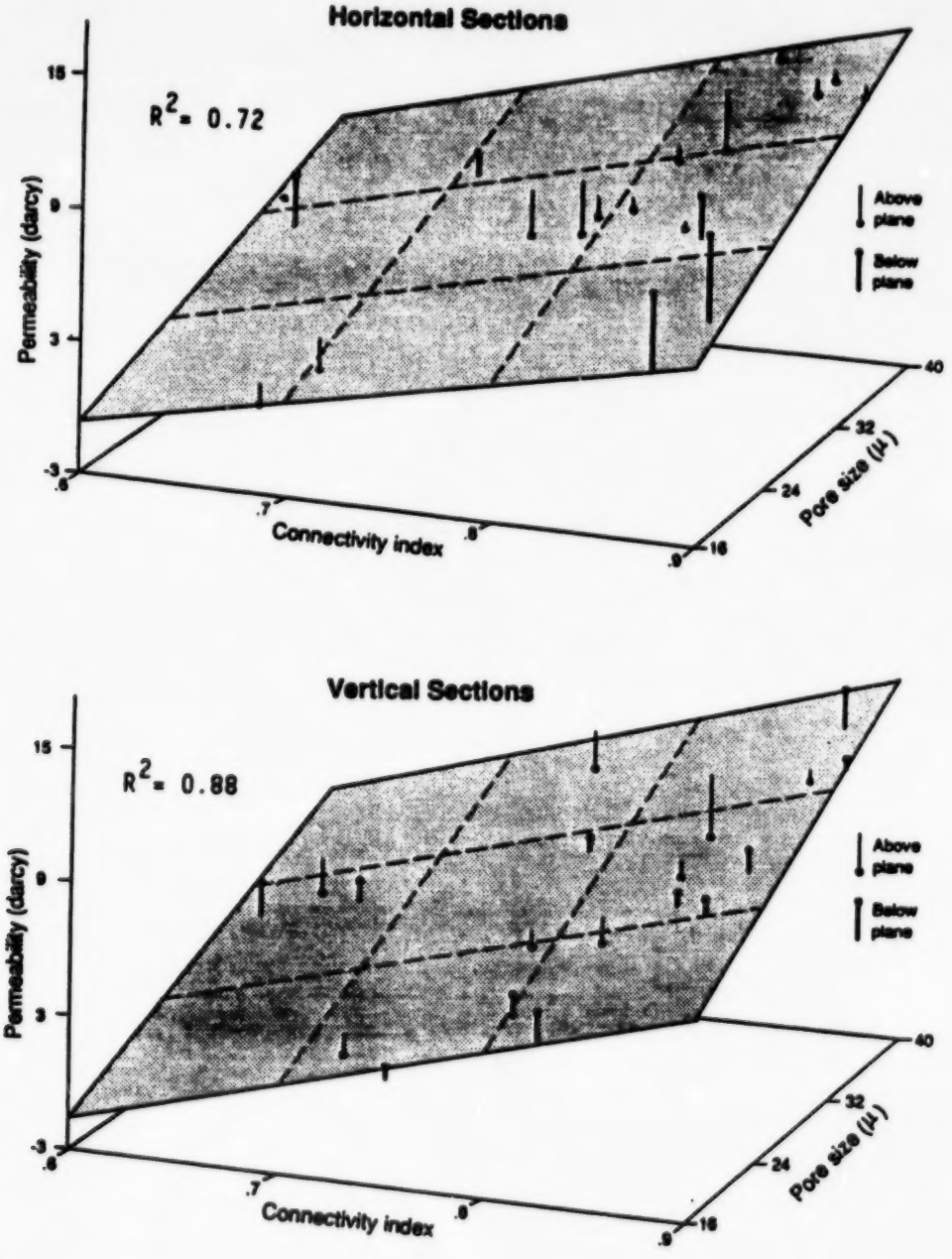

Figure 3. Regression surfaces with pore size and connectivity as independent variables, and permeability as dependent variable. Solid circles are the data projected on the surfaces (predictions) and vertical lines indicate the distances between data points and their projections (residuals).

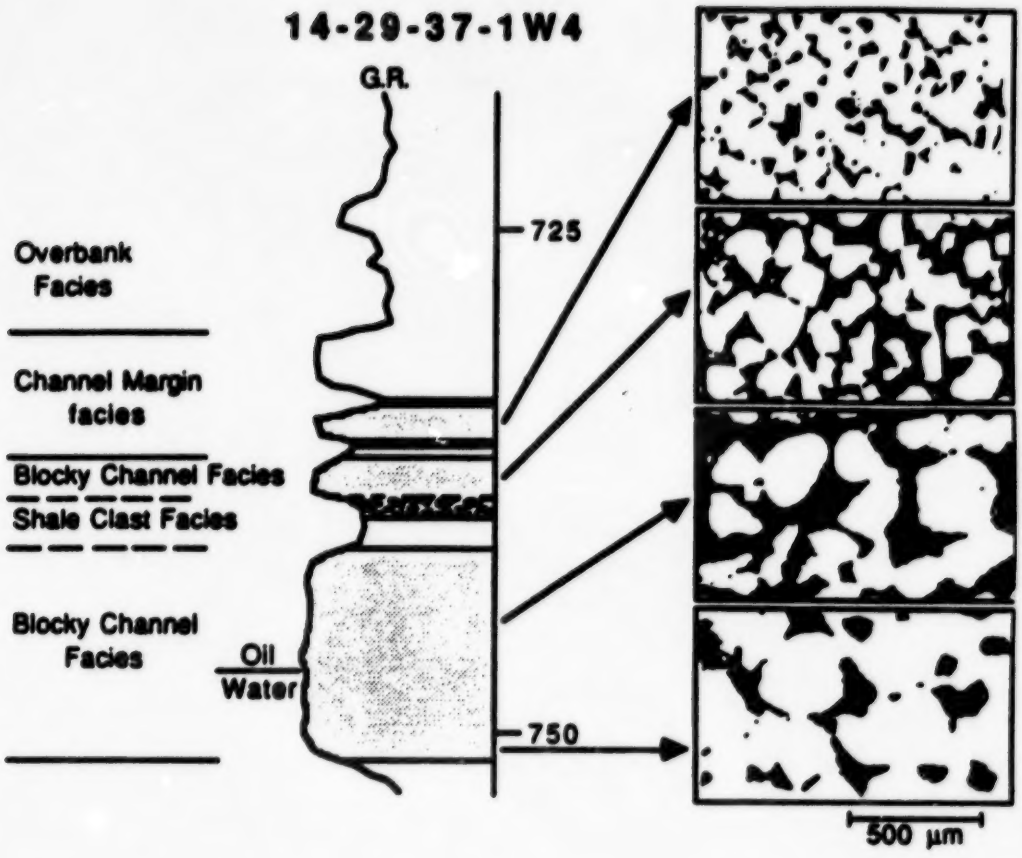

Figure 4. Characteristic pore system end members for the reservoir lithofacies.

EFFECTS OF SHALE CLASTS ON RESERVOIR FLOW PROPERTIES

STEFAN BACHU AND DAVID CUTHIELL

ABSTRACT

Detailed data from the shale clast zone of the Provost Upper Mannville B Pool reservoir have been used in a numerical study of the effects of heterogeneities on reservoir flow properties. Shale clast zones are characterized by several scales of heterogeneity. At core scale, the heterogeneity consists of low permeability shale clasts of variable size, shape and orientation embedded in a sand matrix of much higher permeability. The spatial distribution of clasts is statistically uniform over regions of core size. However, at larger scales, significant variations in the clast distribution are apparent and at the largest scale, the entire shale clast zone comprises discrete layers of clasts interbedded with layers of oil sand. At this scale the geometry and distribution of clast layers characterize the heterogeneity. Because the heterogeneity changes with the scale being considered, a scaling-up approach is required to predict large-scale effective flow properties of the shale clast zone.

The first step of this scaling-up procedure is the prediction of flow properties at the core scale. Numerical flow simulations at this scale were based on actual clast distributions from core and entailed both steady-state and transient numerical experiments. Steady-state effective permeability of a core-scale region is found to depend primarily on the shale clast fraction and on the permeability contrast between the clasts and the matrix. Generally, the effective permeability has a value between the geometric and arithmetic averages of the sand and shale permeabilities. Its dependence on shale clast fraction can be described empirically by a power-average model. The predominantly sub-horizontal orientation of the clasts leads to anisotropy in effective permeability, the vertical component being smaller than the horizontal.

Core-scale flow properties may be scaled up to the shale clast zone scale in two steps. The first step uses the distribution of shale clasts within a layer to compute the effective permeability of the layer. Core data provides only a one-dimensional picture of a layer. However, with plausible assumptions, the shale clast fraction variations observed in core

may be used to characterize the three-dimensional variability of a layer. Effective permeability of the layer may be estimated by a geometrical mean of core-scale results. The final scaling-up step utilizes the properties of individual shale clast layers to estimate the effective permeability of the entire shale clast zone. Again, with certain assumptions, an approximate value for effective zone permeability may be computed based only on core observations and the previously computed layer properties.

Further details of this work are presented in the following references.

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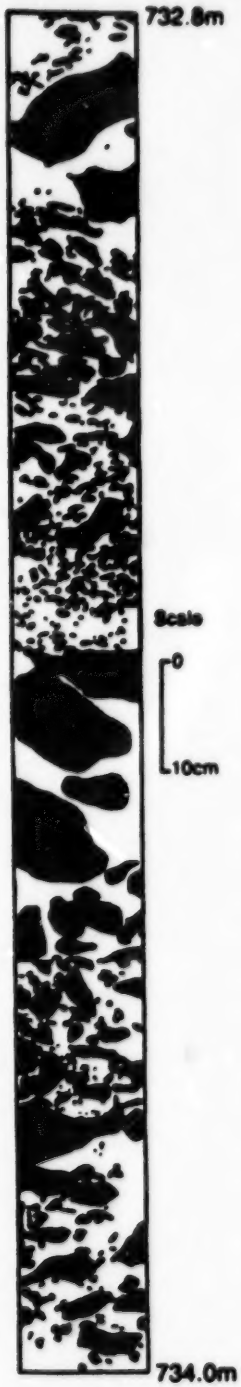
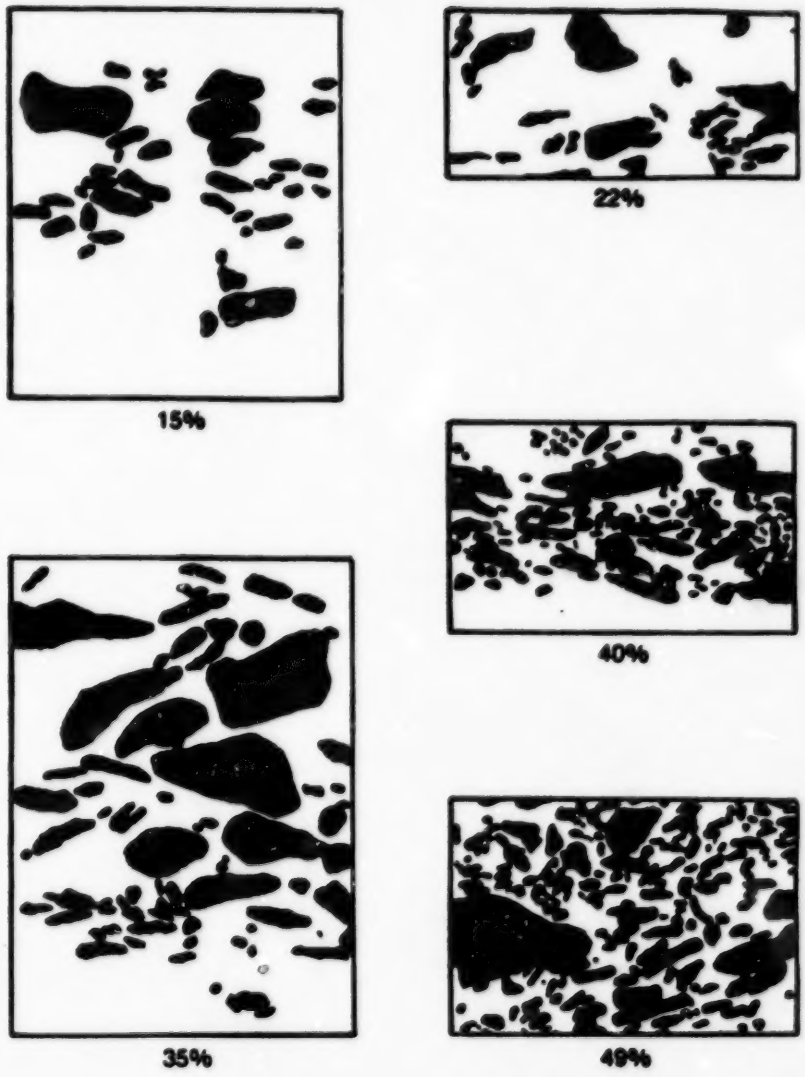
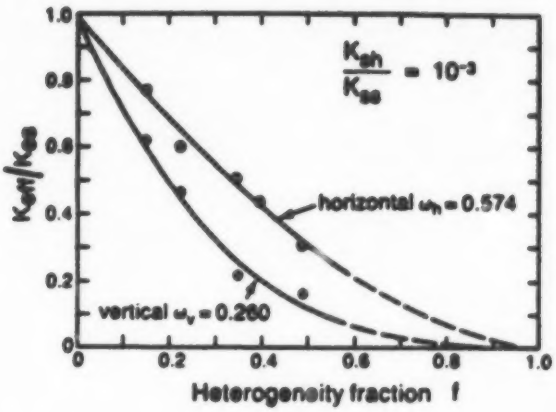


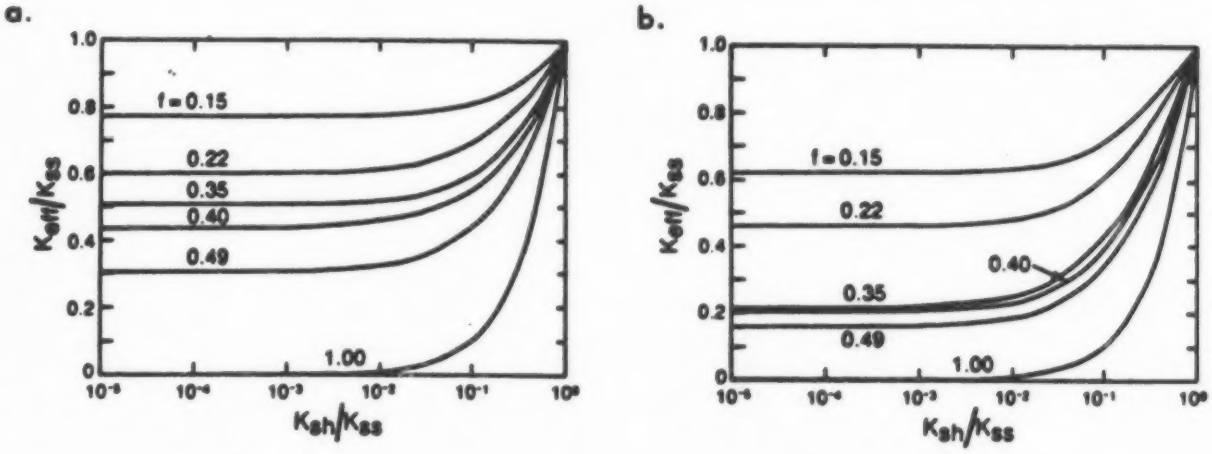
Digitized version of a typical shale clast layer.



Digitized test regions used in core scale flow simulations. Labels indicate shale fractions.

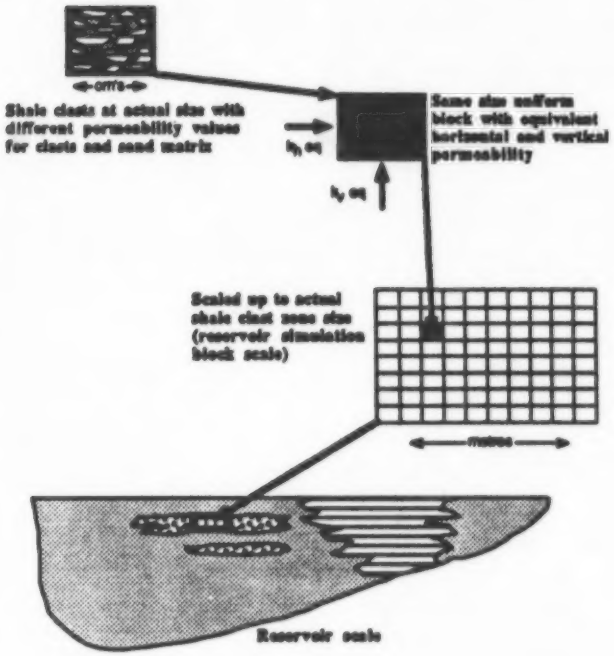


Reduction of effective hydraulic conductivity (horizontal and vertical components) with respect to matrix conductivity, as a function of the heterogeneity fraction f, for the shale-to-sand conductivity ratio $K_{sh}/K_{ss} = 10^{-3}$. The power-average model is fitted to the data points.



Reduction of the horizontal (a) and vertical (b) components of the effective hydraulic conductivity K_{eff} as a function of the shale-to-sand conductivity contrast K_{sh}/K_{ss}, and heterogeneity fraction f.

SCALING UP PROCESS


Shale clasts at actual size with different permeability values for clasts and sand matrix
Same size uniform block with equivalent horizontal and vertical permeability
Scaled up to actual shale clast zone size (reservoir simulation block scale)
Reservoir scale

Diagrammatic representation of the scaling-up process used to obtain grid block values for equivalent permeability in a heterogeneous reservoir.

AOSTRA UNDERGROUND TEST FACILITY

- REGIONAL SETTING
- PHASE A

BRIAN ROTTENFUSSER

JANE PALFREYMAN

ABSTRACT

The sediments of the Lower Cretaceous McMurray Formation and Wabiskaw Member of the Clearwater Formation in the region of the Athabasca Oil Sands consist primarily of unconsolidated sands and muds. The McMurray Formation was deposited in fluvial and estuarine environments with more fluvial influence lower in the section. The Wabiskaw Member sediments were deposited in shallow marine environments as the Clearwater Sea transgressed from the north.

The McMurray Formation was deposited in a north-south trending depression on an erosional surface of Devonian limestone. The highly variable relief on this paleogeographic surface is the most important single control on the distribution of facies and reserves. Structural movement after deposition involved regional tilting to the northwest, on the axis of the Peace River Arch and continued subsidence of local areas due to the solution of underlying Devonian evaporites. Most of the bitumen reserves in the deposit are contained in laterally discontinuous, upward-fining channel sand bodies in the McMurray Formation (Flach, 1985).

The AOSTRA Underground Test Facility (UTF) lease is located near the western edge of the Athabasca-McMurray deposit in Townships 92 and 93, Ranges 12 and 13 W4. In this area, the McMurray thins to the west onto the Wainwright Ridge. The thickest sand and richest bitumen saturations are found near the eastern edge of the lease. Over 100 wells have been drilled to evaluate the lease, with most concentrated near the eastern edge where a north-south trending channel complex 1 to 1.5 km wide contains up to 24 metres of rich oil sands.

At the UTF Phase A, three horizontal well pairs (six wells in total) have been drilled up into the overlying Cretaceous oil sands from tunnels within the underlying Paleozoic carbonates. Each well pair consists of an injection well and a production well, located at approximately 7 metres and 2 metres above the base of the oil sands, respectively. Steam is supplied by injection into the overlying well of

each horizontal pair and the condensate and bitumen are collected from the underlying well. The Chevron HAS (Heated Annulus Steam) Drive process is being tested in an adjacent area. The process uses a vertical injector well drilled from surface and two horizontal wells, a closed HAS well and a production well, drilled from the UTF tunnel.

At the Phase A test site, a grid of 28 vertical boreholes penetrates the reservoir around the horizontal wells. An extensive suite of geophysical logs and 514 metres of core (supplemented by core analysis for grain size, bitumen saturation, porosity and permeability) provide the basis for a detailed geological characterization of the reservoir (Rottenfusser et al., 1988).

At the UTF site, the Cretaceous McMurray Formation is approximately 37 metres thick. The bottom 20 metres of rich oil sands is interrupted by several shaley zones. Most are either shale breccias or heavily burrowed shales, both of which are likely to have some vertical permeability. Overlying the rich oil sands, 17 metres of interbedded oil sand and shale grade up to a sandy shale at the top of the formation. The McMurray is overlain by 2 metres of water saturated Wabiskaw sand which is capped by thick shales of the Clearwater Formation.

The objective of the geological studies has been to provide the parameters to build a detailed reservoir model that reflects the heterogeneities of the Phase A test site. The model has been instrumental in evaluating the effect of geology on development of the steam chambers during the life of the pilot. Studies of reservoir characteristics and facies architecture in the area of proposed expansion of the UTF are providing the basis for planning efficient exploitation of the resource contained in the north-south trending channel complex.

REFERENCES

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Rottenfusser, B.A., Palfreyman, J.E., and Alwast, N.K., (1988), Geology of the AOSTRA Underground Test Facility Site: Proceedings of the Fourth International Conference on the Future of Heavy Crude and Tar Sands, UNITAR/AOSTRA, Edmonton, August, 1988, 26p.

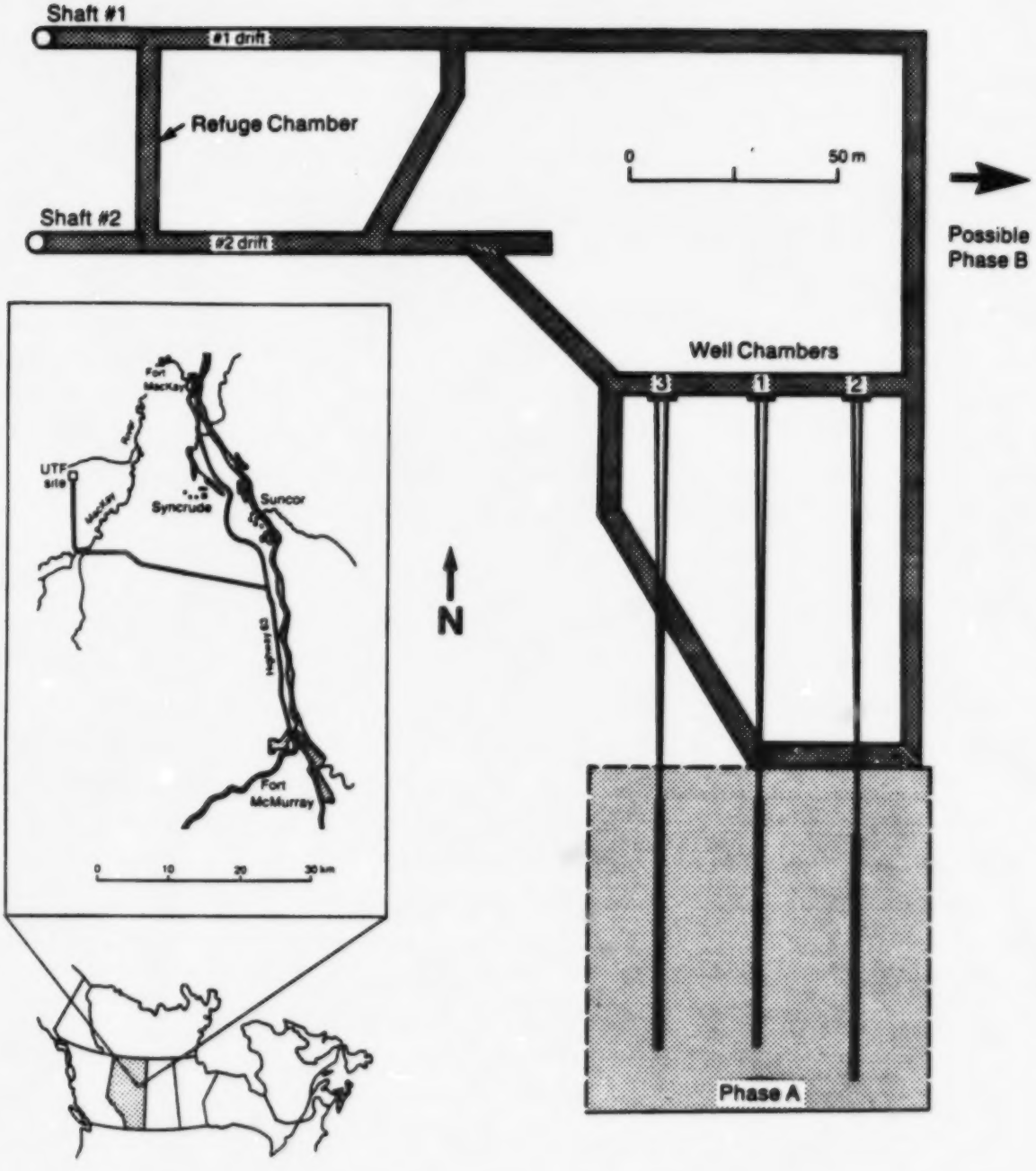


Figure 1. Location of the UTF site and layout of shafts, tunnels and Phase A horizontal well pairs.

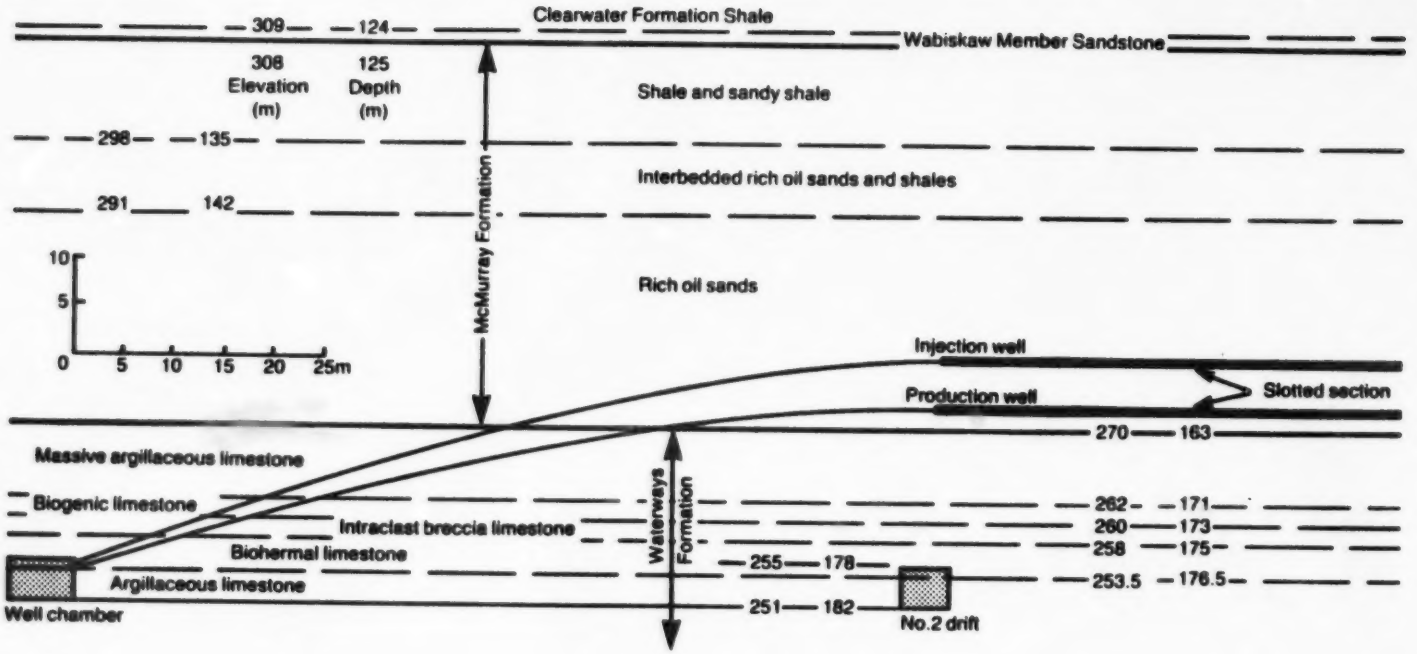


Figure 2. Generalized north-south cross section through Phase A showing relative positions of the tunnels to the injection and production wells.

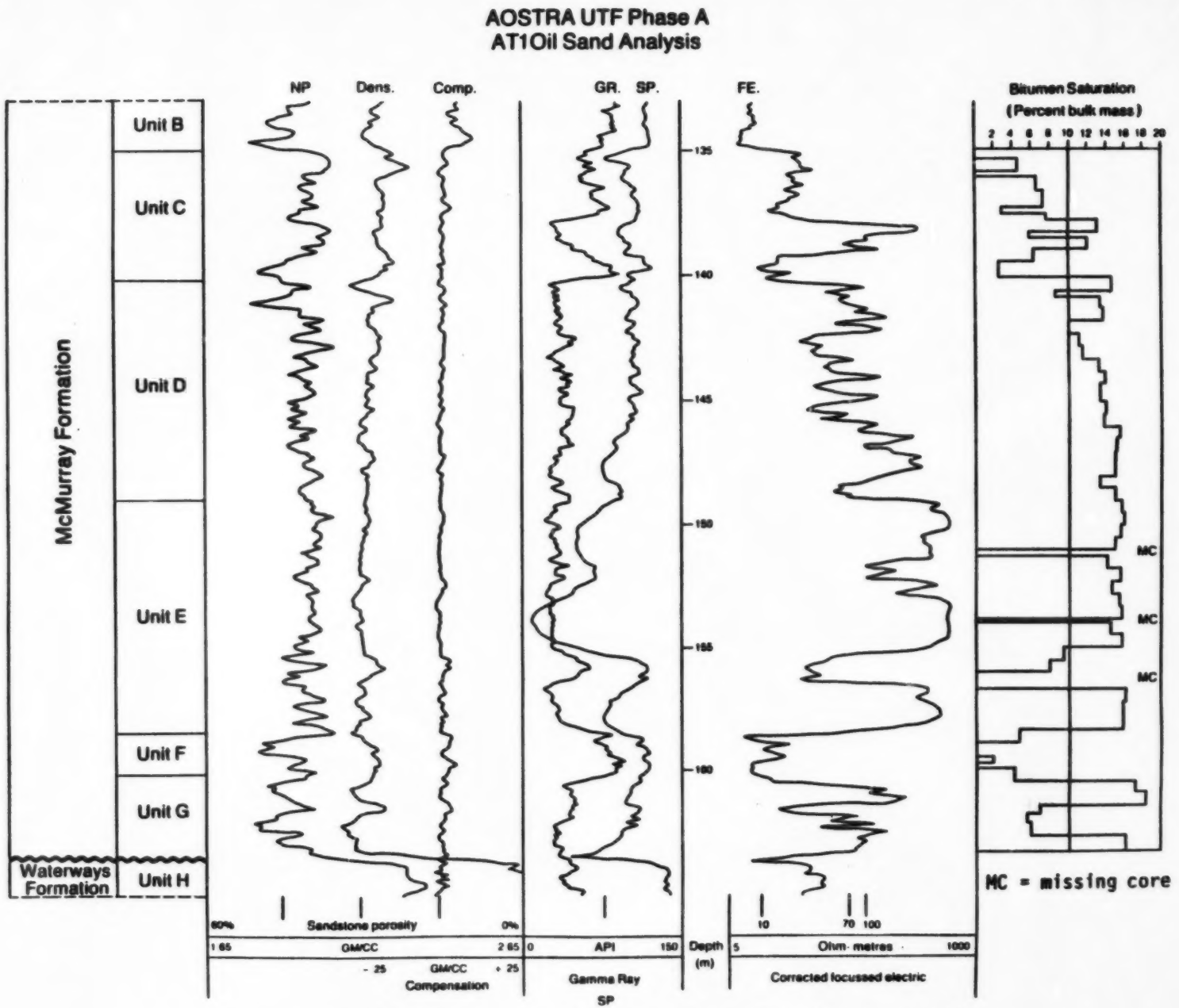
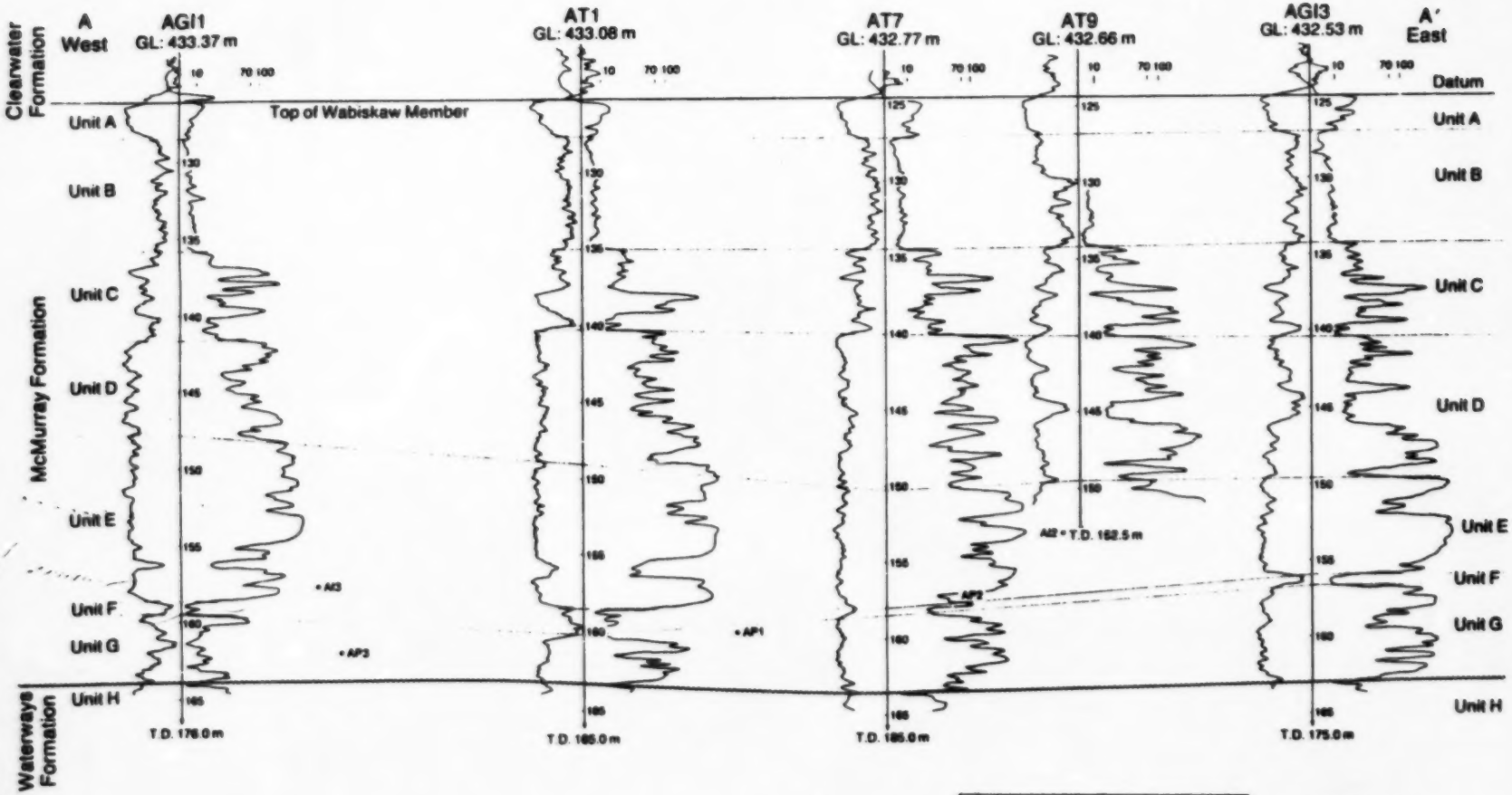


Figure 3. Geophysical logs, stratigraphic units and bitumen saturation from Dean Stark analysis for UTF Phase A well AT1.



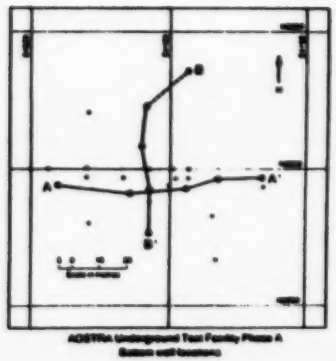


Figure 4. Stratigraphic Cross Section A-A' through UTF Phase A.

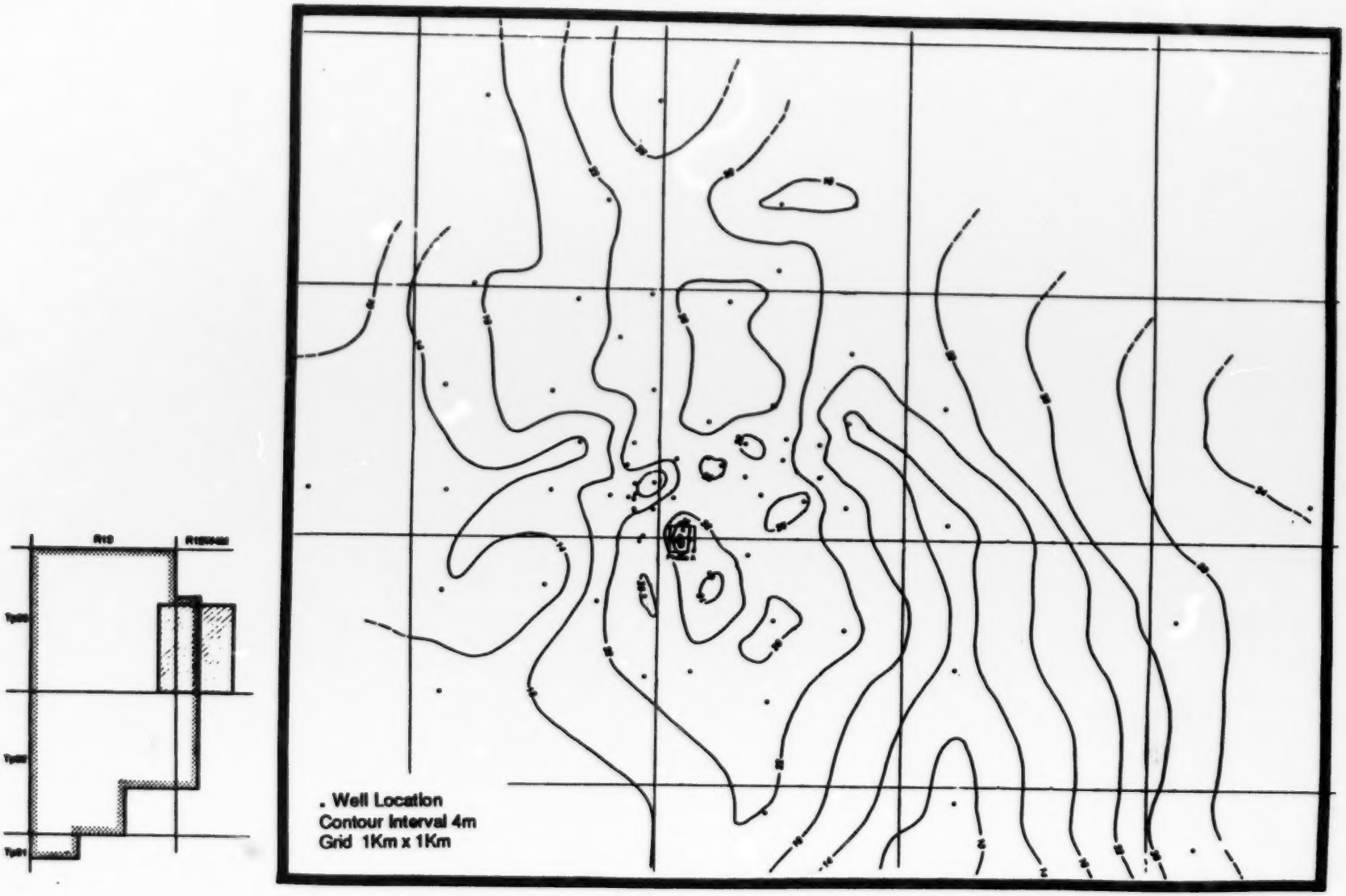


Figure 5. Isopach of Net Sand in the McMurray Formation.